MARITIME ELECTRIC
A FORTIS COMPANY

RECEIVED
MAY 24 2019
The Island Regulatory and Appeals Commission

May 24, 2019

Ms. Cheryl Mosher
Island Regulatory & Appeals Commission
PO Box 577
Charlottetown PE C1A 7L1

Dear Ms. Mosher:

General Rate Application - Docket UE20944
Response to Interrogatories IR-61 to IR-84 from Commission Staff

Please find attached the Company's response to Interrogatories IR-61 to IR-84 from Commission Staff with respect to the General Rate Application filed on November 30, 2018.

Yours truly,

MARITIME ELECTRIC

Gloria Crockett

Gloria Crockett, CPA, CA
Manager, Regulatory & Financial Planning

GCC30
Enclosure
Cc: Nicole McKenna – Carr, Stevenson & MacKay

I N T E R R O G A T O R I E S

Responses to Additional Interrogatories
IR-61 – IR-84
from
Commission Staff

General Rate Application
UE20944

Submitted May 24, 2019

The Island Regulatory and Appeals Commission (the "Commission"), in assessing the General Rate Application submitted by Maritime Electric Company, Limited ("Maritime Electric" or "MECL"), requests responses to the following interrogatories:

<u>The following refer to MECL's responses to the interrogatories of Commission Staff:</u>

IR-61 With respect to **IR-3**:

a. Please explain the rationale and provide justification for including the PEI Energy Corporation Dalhousie and Lepreau Debt Repayment expense as an energy supply cost beginning in 2019 (Schedule 8-4).

b. Please explain the rationale and provide justification for reclassifying the PEI Energy Corporation Dalhousie and Lepreau Debt Repayment expense as energy (rather than demand) beginning in 2019.

Response:

a. The rationale and justification for the inclusion of the PEI Energy Corporation ("PEIEC") Dalhousie and Lepreau debt repayment costs as an energy related cost is outlined in Section 4.1 of the Company's General Rate Application ("GRA"). Further details have also been filed in response to Commission Staff Interrogatories 2 and 27 as well as Multeese Consulting Interrogatories 25 and 26.

The evidence and interrogatory responses provided indicate that the amounts to be recovered relate to the previously deferred energy costs attributed to the Point Lepreau Nuclear Generating Station and Dalhousie Generating Station that were assumed and financed by the Province of PEI under the PEI Energy Accord. Recovery of these costs through customer electricity rates is required pursuant to Section 49 of the Electric Power Act.

Since March 1, 2011, the electricity rates charged to customers have included a per kWh rider on the energy component of customer rates as outlined in Schedule 4-1 of the GRA. However, with the receipt of the Point Lepreau settlement proceeds and PEIEC's intent to refinance the outstanding debt with fixed repayment terms, the annual amount to be recovered on behalf of the Province will be stable and predictable for the Company, the PEIEC and electricity customers. As a result, it is proposed to treat the repayment amounts as an expense to be recovered from customers rather than a per kWh rate rider on customer rates.

Since the amounts to be recovered on behalf of the Province are costs related to deferred energy costs, it is the Company's position that these deferred energy costs should be treated in the same manner as all other energy related costs and included in the ECAM calculation as approved by IRAC in prior Orders. This treatment is consistent with the Commission's past approval (Order UE05-08) to amortize deferred energy related costs through the ECAM.

b. The Company is not proposing to reclassify the amounts to be recovered on behalf of the Province from demand to energy. As detailed in Section 4.1 of the Company's evidence, the recovery of these amounts has, since March 1, 2011, been done as a per kWh rider on the energy rates charged to customers. Likewise, the Company's proposal to treat the fixed repayment amounts prospectively as an energy related cost to be recovered through the ECAM calculation is a consistent approach to recovery as an energy cost.

In response to Multeese Consulting IR-26, the Company states that:

> *"these deferred costs could be separated into Demand-related and Energy-related components, and recovered through adders to the demand charges and energy charges under the various rate classes. However, as a practical matter, these deferred costs are recovered through ECAM (Energy Cost Adjustment Mechanism); i.e. as a component of the energy charges for all rate classes, because most of Maritime Electric's customers do not pay demand charges. (There is no demand charge in the Residential, Street lighting or Unmetered Rates and General Service customers with less than 20 kW of monthly metered demand do not incur a demand charge.)"*

IR-62 With respect to the response to **IR-4**, please explain why the RORA balance continues to accumulate, notwithstanding that these amounts are being refunded to ratepayers.

Response:

IR-4 – Attachment 1 shows that the RORA account is comprised of two components: the pre-2016 RORA which is currently being refunded through energy rates and the post-2015 RORA which has been deferred under Order UE16-04 and is proposed to be refunded over the 2019-2021 period at a rate of $0.00250/kWh. The derivation of the over earnings amounts that contribute to the post-2015 RORA balance is provided in response to IR-68.

<u>Pre-2016 RORA</u>

The pre-2016 RORA was established by IRAC in Order UE11-04 to defer, with interest, any earnings in excess of the approved return on average common equity during the years of the PEI Energy Accord (2011-2015). The amounts, recorded as additions to the pre-2016 RORA balance during these years, and are shown in Schedule 5-4 of the GRA evidence totalling $16,820,009 plus interest of $1,358,345.

From March 1, 2013 to February 29, 2016, customer electricity rates, as legislated under the PEI Energy Accord, included a return or refund of RORA amounts to customers for the balance at December 31, 2012 as illustrated in Schedule 5-4. From 2013 to 2015, amounts refunded ranged from $648,556 to $843,956.

However, during the remaining three years of the PEI Energy Accord (2013-2015), the Company also recorded a RORA which was deferred and added to the pre-2016 RORA account for future refund as per UE11-04. This accumulated balance was ordered by IRAC under Order UE16-04 to be refunded to customers over the period March 1, 2016 to February 28, 2019 at the rates approved by the Commission in Appendix 2 of Order UE16-04.

Schedule 5-4 illustrates the accumulation of RORA additions, interest and refunds to the pre-2016 RORA balance from its original establishment in 2011 to February 28, 2019. The forecast residual balance of $768,700 shown in Schedule 5-4 is proposed to be transferred to the post-2015 RORA for refund as part of the post-2015 RORA balance.

<u>Post-2015 RORA</u>

Order UE16-04 established the post-2015 RORA account for any over earnings for the years 2016-2018. During these years, the Company recorded actual RORA amounts for 2016 and 2017 and had forecast further RORA amount for 2018 as outlined in Schedule 5-5 of the GRA. The calculation of these RORA amounts and the projected balance of the post-2015 RORA account at February 28, 2019 has been provided in response to Commission Staff IR-7.

The post-2015 RORA amounts recorded for the year 2016-2018 have caused the total RORA balance to accumulate during this period because they were deferred for future refund to customers pursuant to UE16-04. The Company has proposed in Section 5.3.2 of the GRA evidence to refund the projected balance to customers over the period March 1, 2019 to February 28, 2022 at a rate of $0.00250/kWh. The calculation of this refund rate has been provided in response to Commission Staff IR-8. Based upon these forecast amounts, the RORA account balance is projected to be fully refunded and at a nil balance by February 28, 2022.

IR-63 In response to **IR-6**, MECL states that the proposals in the General Rate Application "*do not result in excess earnings during the period so there are no additions to the RORA account projected*":

a. As MECL has a history of overearning, as evidenced by the RORA account balance, please explain why MECL does not anticipate excess earnings between 2019 and 2022.

b. Please explain what steps MECL has taken to ensure that it does not over earn during the period of the proposed General Rate Application.

Response:

a. Maritime Electric is regulated by IRAC under a traditional cost of service regulatory model wherein customer electricity rates are confirmed by IRAC to recover the cost of providing service to customers. The first step under cost of service regulation is to establish the Company's revenue requirement which is equal to its estimated cost of service for the period under which rates are set.

The Company's General Rate Application ("GRA") evidence, supporting studies, experts reports and detailed responses to interrogatories provide the Company's analysis, proposals and justification for the projected costs it seeks to include in the determination and confirmation of its annual revenue requirement. The annual revenue requirement will, in turn, be used to establish customer electricity rates.

Schedule 14-4 in Section 14 of the Company's GRA outlines the forecast of the various components of annual revenue requirement for the years 2019-2021. These components include operating expenses (as detailed in Schedule 14-2) interest costs, amortization of fixed assets and other regulatory deferrals, income taxes and the proposed return on average common equity. The projected annual revenue requirement does not include provision to recover any excess earnings amount from customers.

b. Maritime Electric has developed its projected estimates of those costs to be recovered from customers based upon analysis of historical and future cost trends, legislative and contractual obligations, independent expert analysis and reviews and the professional judgement of employees within the Company having industry experience. These projected costs, as outlined in Schedule 14-4 comprise the annual revenue requirement proposed to be recovered.

The total projected annual revenue requirement is recovered from electric revenue and other revenue as outlined in Schedule 14-7 of the GRA evidence. Other revenue, as detailed in Schedule 14-5, is derived from the Open Access Transmission Tariff as approved by IRAC along with estimated revenues from the Late Payment Fees, Connection Fees and other miscellaneous revenue.

The remainder of the annual revenue requirement is recovered through electricity revenues from customers based on the Company's forecast of electricity sales and load during the period. As discussed in Section 7 of the GRA evidence, the Company's sales forecast is derived from detailed sales regression analysis that reflects a number of variables.

These analyses, inputs, reviews and assessments are compiled and presented in the various submissions filed by the Company to ensure that the proposed costs are prudent and justified and that the rates proposed are established only to that level necessary to provide the Company the opportunity to fully recover its costs.

IR-64 The response to **IR-7** references "*Non Recoverable Fortis Inc. Costs*". Please explain what the non-recoverable Fortis Inc. costs are and how they are calculated.

a. Since the date the Commission disallowed Fortis Inc. costs, please provide a detailed working paper of the total disallowed expenses per year.

Response:

Non recoverable Fortis Inc. costs represent Maritime Electric's pro rata share of the Fortis Inc. general operating costs allocated and paid by Maritime Electric. Prior to 2017, the Fortis Inc. operating costs were allocated to the various subsidiaries on the basis of total assets. In 2017, Fortis adopted a weighted dual factor allocation methodology for 2017 and future years based upon total assets (75 per cent weighting) and total controllable operating expenses (25 per cent weighting).

As a member of the Fortis group of companies, Maritime Electric and its customers benefit from lower costs in such areas as insurance, financial services and group purchases of materials and equipment. In addition, the network of knowledge and expertise across the Fortis group yields further benefits to the Company and PEI electricity customers through best practices and efficient information sharing. As a result, Maritime Electric's view is that these benefits far outweigh the costs recovered by Fortis and, as a result, the Fortis Inc. costs should therefore be recoverable from electricity customers.

However, pursuant to Commission Order UE09-02, these costs are not recoverable from Maritime Electric electricity customers and therefore are excluded from revenue requirement for purposes of establishing electricity rates and in the determination of regulated earnings for the year. The attached schedule IR-64 - Attachment 1 provides a breakdown of the components of the Fortis Inc. non recoverable costs paid by Maritime Electric since 2009.

IR-65 In response to **IR-9(c)**, MECL states that it "*has identified the need for additional on-Island generation over the long-term*":

a. Please provide full particulars of the need identified by Maritime Electric's system planning.

b. Please advise how Maritime Electric intends to address the need for additional on- Island generation.

Response:

a. The table below is an expanded capacity forecast that shows Maritime Electric's capacity situation to 2028:

Schedule of Planning Capacity Requirements and Resources											
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
MECL capacity requirement (MW):											
- MECL peak load	244	256	265	266	272	282	284	290	301	303	309
- less interruptible load	14	14	14	14	14	14	14	14	14	14	14
- plus 15% planning reserve	34	36	37	37	38	39	39	40	41	41	42
Subtotal	**264**	**277**	**286**	**286**	**290**	**300**	**300**	**305**	**315**	**315**	**321**
MECL capacity resources (MW):											
- Charlottetown Thermal Plant	55	48	38	38	-	-	-	-	-	-	-
- Borden Plant	40	40	40	40	40	40	40	40	40	40	40
- Combustion Turbine 3	49	49	49	49	49	49	49	49	49	49	49
- Point Lepreau (at Murray Corner)	29	29	29	29	29	29	29	29	29	29	29
- Wind ELCC	21	21	24	24	24	24	24	24	24	24	24
- Short term capacity purchases[1]	80	105	110	110	145	145	-	-	-	-	-
- Incremental capacity required to avoid deficit[2]	-	-	-	-	10	15	160	165	175	175	180
Subtotal	**274**	**292**	**290**	**290**	**292**	**302**	**302**	**307**	**317**	**317**	**322**
Surplus (deficit)	**10**	**15**	**4**	**4**	**2**	**2**	**2**	**2**	**2**	**2**	**1**

In order to address capacity shortages, Maritime Electric can either a) procure additional generating capacity from mainland sources or b) build additional on-Island dispatchable generation that is capable of providing generating capacity.

Maritime Electric currently procures approximately one third of its capacity through short-term off-Island capacity purchases, and an additional 10 per cent from its participation in

[1] Short-term capacity purchases currently under contract.
[2] Maritime Electric assumes that it will procure the small amounts of required incremental capacity in 2022 and 2023 through short-term capacity purchases from off-Island sources.

Point Lepreau. Maritime Electric will procure 53 per cent of its capacity via short-term capacity purchases upon closure of the CTGS in 2022. Without additional on-Island dispatchable generating capacity this is projected to increase to 56 per cent by 2028, bringing the total off-Island capacity supply to approximately two-thirds of the total. The closest operating generation is located in Saint John, NB, roughly 250 km from the Island.

From a planning capacity perspective (planning capacity ensures there are enough supply resources in the region to safely survive loss of the largest source), Maritime Electric can economically access sufficient reserves up to 2027 (when the Mactaquac Generating Station is scheduled to be taken offline for extended maintenance).

However, Maritime Electric's main concern is the continued reliability of NB Power's transmission system. Maritime Electric believes that having two-thirds operating capacity supply exposure to periodic transmission limitations in New Brunswick is a potential future risk.

In addition, the on-Island 138 kV transmission system may be unable to maintain system stability and support voltage above the current 300 MW import level (the existing NB-NS/PEI interface transfer limit). The impact on the Island system of mainland imports in excess of 300 MW has not been studied in detail, and the Company will initiate a detailed study of the Island transmission system to determine its capabilities under high import situations. The Company will investigate the use of transmission, generation and peak load management techniques – such as direct load control or use of smart meters combined with time of use rates – in order to accommodate its growing peak load and potential high imports.

b. Maritime Electric will undertake the following to determine if additional on-Island generation is the optimal solution:

- Monitor customer load growth and technology trends, and revise load forecasts as necessary to determine ongoing capacity requirements;
- Continuously assess the availability of mainland capacity;
- Monitor the load growth in southeastern New Brunswick that may impact the availability of capacity purchases;
- Monitor NB Power's transmission system reliability as it pertains to PEI; and
- Compare generation solutions to other available options, such as transmission, direct load control or time of use rates.

IR-66 In response to **IR-9**, MECL indicates that the CTGS site will remain used and useful to ratepayers.

a. Please explain how the entire remaining property meets the criteria for used and useful.

b. Please provide a tentative timeline for future development projects at this site.

Response:

a. The CTGS site (which will continue to accommodate Combustion Turbine 3 ('CT3') beyond the decommissioning of the CTGS) consists of six parcels of land with a total land area of approximately 13.7 acres.

Maritime Electric purchased properties on Grafton Street and Cumberland Street in the late 1980s to enhance the buffer distance between its operations and surrounding residential areas and to provide future expansion capability.

The removal of the CTGS building from the site does not result in the land upon which it rests ceasing to become used and useful to the CT3 power generating station that will remain on site. The Cumberland Street site will remain used and useful following removal of the CTGS building. CT3 will remain at the site. In the short term this land will provide an additional distance buffer to the operation of CT3 and will improve laydown areas and accessibility on a congested site.

In the longer term, this land will provide Maritime Electric with the ability to locate additional on-Island generation or other generation alternatives (i.e. battery storage). IR-66 - Attachment 1 shows a potential future use of the site to locate future generation. In this attachment, there are two potential locations for future generation shown. One location is to the north of CT3 and the other potential location is to the south of CT3. Each location has different advantages and disadvantages which would have to be carefully weighed if future generation were to be constructed. IR-66 – Attachment 1 also shows the proposed location for a new CT3 Balance of Plant (BOP) Equipment Building to the north of CT3.

Existing infrastructure such as the Fuel Tank Farm, Charlottetown Substation, Substation Control Building, Energy Control Centre (ECC) Building and X4 Transformer are also shown in IR-66 – Attachment 1.

At this time it is difficult to predict future usage for the site. That said, it provides many options such as locating additional generation or storage infrastructure that could efficiently make use of existing infrastructure and is close to the PEI load centre. As well, the 1.2 acre parcel of land that much of the existing building is on is leased from the Cumberland Trust for a minimal annual cost and, because of its strategic location, should be retained.

b. Please refer to the response to IR-65.

IR-67 In **Section 6**, MECL identifies the CTGS estimate as a Class "B" estimate with an accuracy range of -20% to +30%. Please provide full particulars regarding MECL's plans to move forward with this project, including any plans to obtain refined estimates.

Response:

Maritime Electric will move forward with this project upon receiving approval from the Commission. The Company will update the CTGS Decommissioning Cost Estimate on a periodic basis as the scope of work is further defined. For instance, preliminary project tasks such as stakeholder consultations and conditions arising out of the Environmental Impact Assessment (EIA) process can have a significant influence on decommissioning scope and costs. Maritime Electric will update cost estimates at those times and will provide any substantive updates to the Commission.

IR-67 – Attachment 1 includes the letter from GHD describing the cost estimate classification that GHD used in developing the closure cost forecasting as part of the 2018 Decommissioning Study, and GHD's recommendations for future refinement of the cost estimate.

The table below compares the Treasury Board of Canada and the Association for the Advancement of Costing Engineering (AACE) cost estimate classification systems that are referenced in GHD's letter.

Association for Advancement of Costing Engineering (AACE) International			**Treasury Board (TB) of the Canadian Federal Government**		
Estimate Class	**End Usage**	**Percent of Project Completion**	**Estimate Class**	**End Usage**	**Percent of Project Completion**
	Estimating Methodology	**Expected Accuracy Range**		**Estimating Methodology**	**Expected Accuracy Range**
Class 5	Concept Screening	Project Completion: 0%-2%	**Class D**	Screening of various alternative solutions	Project Completion: 1% to 5%
	Stochastic, Judgment, or Analogy	High: +100% to -50% Low: +30% to -20%		Various *(describe)*	Lowest
Class 4	Study or Feasibility	Project Completion: 1%-15%	**Class C**	Seeking preliminary project approval	Project Completion: 5% to 15%
	Equipment Factored or Parametric Models	High: +50% to -30% Low: +20% to -15%		Measured, priced, parameter quantities where possible	Low
Class 3	Budget, Authorization, or Control	Project Completion: 10%-40%	**Class B**	Seeking effective project approval	Project Completion: 20% to 35%
	Semi-Detailed Unit Costs with Assembly Level Line Items	High: +30% to -20% Low: +10% to -10%		Mainly measured, priced, detail quantities	Medium
Class 2	Control or Bid/Tendering	Project Completion: 30%-70%			
	Detailed Unit Cost with Forced Detailed Take-Off	High: +20% to -15% Low: +5% to -5%			
Class 1	Check Estimate or Bid/Tendering	Project Completion: 50%-100%	**Class A**	Compliance with effective project approval (budget)	Project Completion: 95% to 100%
	Detailed Unit Cost with Detailed Take-Off	High: +15% to -10% Low: +3% to -3%		Measured, priced full detail quantities	High

IR-68 In response to **IR-13**, the actual energy sales for 2016 and 2017 were less than forecasted (using the regression analysis model). Although energy sales were less than forecasted, MECL still over earned in each of 2016 and 2017. Please explain why MECL over earned in 2016 and 2017, notwithstanding lower than forecasted energy sales.

Response:

The table below shows the forecast and actual sales for 2016 and 2017.

Comparison of Actual to Forecast Sales				
Year	**Forecast sales (GWh)**	**Forecast growth (%)**	**Actual sales (GWh)**	**Actual growth (%)**
2014			1,167.7	
2016	1,195.3	2.4	1,188.6	1.8
2016	1,193.7	(0.1)	1,188.4	(0.0)
2017	1,218.4	2.1	1,208.1	1.7

In response to Commission Staff IR-43, the Company provided updated Schedules of Inputs for 2016 and 2017 showing the original forecast revenue and expense amounts approved in Order UE16-04 as compared to the actual results for those years. The variance from forecast to actual for each revenue or expense line item in these schedules together comprise the total amount over earned in these years.

These variances, based on the forecast and actual revenue and expenses outlined in response to Commission Staff UE-43 are summarized in the table below.

Schedule of Inputs – Variance of Actual from Forecast						
	2016			2017		
	As Approved Order UE16-04	Actual	Variance	As Approved Order UE16-04	Actual	Variance
Basic Rate Revenue[1]	178,950,000	178,157,320	(792,680)	187,114,000	185,326,722	(1,787,278)
Transmission Revenue[2]	8,110,000	8,390,842	280,842	12,380,000	7,961,884	(4,418,116)
Miscellaneous Revenue	1,627,000	1,763,211	136,211	2,025,000	1,962,405	(62,595)
Energy Costs[1]	111,986,000	111,185,220	800,780	117,726,000	116,106,441	1,619,559
Distribution & Transmission[3]	8,176,000	7,268,360	907,640	8,727,000	7,752,015	974,985
Transmission – OATT (Cable)[2]	-	-	-	4,133,000	-	4,133,000
Transmission – OATT (Other)	6,665,000	6,842,196	(177,196)	6,813,000	6,272,903	540,097
Corporate[4]	10,094,000	9,384,106	709,894	10,484,000	9,059,706	1,424,294
Amortization	21,139,000	21,039,434	99,566	22,397,000	22,223,525	173,475
Financing	12,388,000	12,378,373	9,627	12,433,000	12,251,808	181,192
Income Taxes	5,768,000	5,754,350	13,650	5,943,000	5,940,740	2,260
Weather Normalization Reserve	-	(126,031)	126,031	-	(52,155)	52,155
Net Earnings	12,471,000	12,485,365	(14,365)	12,863,000	12,928,143	(65,143)
Rate of Return Adjustment (RORA)			2,100,00			2,767,885

1 2016 sales 0.45% cent below forecast mainly due to a milder winter, resulting in lower energy purchases (0.57%) than forecast.

2 Variance in 2017 due to new interconnection lease charges originally forecast to be recovered through OATT in the GRA but instead recovered under a Debt Collection Agreement, therefore recorded directly as an energy charge and recovered through ECAM.

3 2016 variance mainly due to lower than expected spending in transmission line ROWs ($230K), T&D line maintenance ($345K) and property taxes ($245K); 2017 variance mainly due to lower than forecast line and transmission maintenance costs due to relatively low storm activity ($500K) and lower property taxes ($300K).

4 2016 variance mainly due to lower than forecast customer service costs ($175K), lower regulatory costs ($145K) and lower corporate services and support ($320K); 2017 variance mainly due to lower than forecast customer service costs ($370K), lower finance and accounting costs ($150K), lower regulatory costs ($165K) and lower corporate services and support ($525K).

IR-69 In response to **IR-16**, MECL states that the load forecast in the General Rate Application is based, in part, on the assumption that the PEI Energy Corporation/efficiencyPEI Electricity Efficiency & Conservation Plan ("EE&C Plan") would begin in October 2018. The EE&C application is currently before the Commission and, as such, did not begin in October 2018. Please advise what impact this has on the load forecast included in the General Rate Application.

Response:

Shown below is efficiencyPEI's forecast of energy efficiency savings, along with the calculation of annual savings based on the assumption that programming would begin in October 2018. These formed part of Maritime Electric's response to IR-16.

efficiencyPEI Forecast of Energy Efficiency Savings – as of late 2017			
Government fiscal year	**Incremental savings for Residential (GWh)**	**Incremental savings for Businesses (GWh)**	**Total incremental savings (GWh)**
2018/2019	1.8	1.5	3.3
2019/2020	3.2	3.5	6.7
2020/2021	4.0	5.5	9.5

The sales forecast for Maritime Electric's current GRA filing was prepared in August 2018. The forecast of the impact of energy efficiency was based on efficiencyPEI's forecast, as follows:

- Program delivery was assumed to begin in October 2018
- Maritime Electric serves 90 per cent of the PEI electricity load, so it would see 90 per cent of the energy savings
- Incremental annual savings would continue at 9.5 GWh after 2020/2021
- Savings for 2018: (3.3 GWh x 0.25) x 0.9 = 0.7 GWh
- Savings for 2019: (3.3 GWh x 0.75 + 6.7 GWh x 0.25) x 0.9 = 3.7 GWh
- Savings for 2020: (6.7 GWh x 0.75 + 9.5 GWh x 0.25) x 0.9 = 6.7 GWh
- Savings for 2021: (9.5 GWh x 0.75 + 9.5 GWh x 0.25) x 0.9 = 8.6 GWh

Assuming that programming started in April 2019 (efficiencyPEI instant rebates on LED light bulbs were available in stores in April), the revised calculation of incremental annual savings is:

- Program delivery began in April 2019
- Maritime Electric serves 90 per cent of the PEI electricity load so it would see 90 per cent of the energy savings
- Incremental annual savings would continue at 9.5 GWh after 2021/2022
- Savings for 2018: 0 GWh
- Savings for 2019: (3.3 GWh x 0.75) x 0.9 = 2.2 GWh
- Savings for 2020: (3.3 GWh x 0.25 + 6.7 GWh x 0.75) x 0.9 = 5.3 GWh
- Savings for 2021: (6.7 GWh x 0.25 + 9.5 GWh x 0.75) x 0.9 = 7.9 GWh

The table below shows a comparison of the two calculations of energy efficiency savings.

Impact of efficiencyPEI Programming Start Date on Annual Energy Savings					
	Forecast Efficiency Savings for October 2018 Start (GWh)		Forecast Efficiency Savings for April 2019 Start (GWh)		Difference (GWh)
Year	Incremental	Cumulative	Incremental	Cumulative	Cumulative
2018	0.7	0.7	0.0	0.0	0.7
2019	3.7	4.4	2.2	2.2	2.2
2020	6.7	11.1	5.3	7.5	3.6
2021	8.6	19.7	7.9	15.4	4.3

The table below shows how the August 2018 sales forecast would have differed had it been based on an April 2019 start for efficiencyPEI's energy efficiency programming.

Impact of a April 2019 Start Date for efficiencyPEI on the August 2018 Sales Forecast					
	August 2018 sales forecast			Adjusted Aug 2018 forecast	
Year	Annual sales (GWh)	Increase (%)	Reduction in efficiency savings (GWh)	Annual sales (GWh)	Increase (%)
2017	1,208.1				
2018	1,234.8	2.2	0.7	1,235.5	2.3
2019	1,267.0	2.6	2.2	1,269.2	2.7
2020	1,300.9	2.7	3.6	1,304.5	2.8
2021	1,321.4	1.6	4.3	1,325.7	1.6

The Company does not consider these estimated changes in the load forecast from a delay in the start of programming to be material.

IR-70 In response to **IR-17**, MECL states that the ECAM is intended to capture all fluctuations in the cost of purchased and produced energy from the base rate included in customer rates. Based on this interpretation, the ECAM could be seen as a disincentive to minimize energy costs as Maritime Electric is guaranteed to recover any fluctuation in cost from ratepayers. Please comment and explain what steps MECL has taken to ensure that energy costs are minimized for ratepayers.

Response:

Maritime Electric believes that the ECAM, as currently approved by IRAC, benefits the Company's customers because it provides a degree of stability with respect to the refund or recovery of unplanned energy cost variations from forecast. In addition, it is generally viewed as supportive of the business risk assessment by the Company's credit rating agency Standard & Poors as noted in their most recent ratings report[3] dated April 3, 2018 and filed with the General Rate Agreement (GRA) evidence as Appendix 12. In its report S&P states:

> *"Regulation is generally supportive, where MECL benefits from various regulatory mechanisms like the energy cost adjustment mechanism, which allows for full recovery of prudently incurred costs."*

Concentric Energy Advisors[4] also reference ECAM on Page 48 of their Cost of Capital Report filed as Appendix 13 to the General Rate Agreement filing. Concentric views ECAM as a positive factor in mitigating the risk against costs that tend to fluctuate significantly from year to year. The ECAM provides for recovery of fluctuations in prudently incurred energy related costs from contracts and agreements previously filed and reviewed by IRAC.

Maritime Electric has taken and continues to take steps to minimize energy costs for Island ratepayers:

- The Energy Purchase Agreement ('EPA') negotiated with New Brunswick Energy Marketing ('NBEM') is the single largest component of off-Island energy purchases. It represents approximately 55 per cent of total energy costs for 2018. Maritime Electric's response to interrogatory IR-44 of the Commission Expert on October 22, 2018 provides detail into the analysis carried out to ensure the EPA pricing was competitive. The analysis concluded that the energy pricing competitive, fair and reasonable for a contract that delivered price certainty for Maritime Electric customers and with no exposure to carbon tax or currency exchange risks for a five year period. The contract also enabled maximizing the extraction of CTGS' value right up to its planned closure.

- Maritime Electric's operating contribution to ECAM is actively managed to minimize costs. CTGS staff have been redeployed to avoid the addition of staff in other areas of the Company. This preserves having the technical expertise and experience to operate and provide maintenance of CTGS equipment for safe operation while minimizing costs.

3 Page 2 of S&P Global Ratings Direct Report – Summary of Maritime Electric Co. Ltd., April 3, 2018
4 Page 48 of Concentric Energy Advisors Cost of Capital Report, November 27, 2018

- Wind energy represented 21 per cent of the total energy costs in 2018. Windfarm power purchase agreements were negotiated between Maritime Electric and the windfarm proponents. Maritime Electric had to file with the Commission, and receive Commission approval for, each wind energy power purchase agreement. Energy imbalance costs that result from windfarms either over- or under-producing (as compared to their scheduled amounts) are recovered from the windfarm generators in order that Maritime Electric customers do not bear this cost. Additionally, ratepayers are protected from Hold to Schedules where the costs incurred to run on-Island conventional generation are borne by the Transmission Customer who is off schedule. A Hold to Schedule is typically imposed by the NB System Operator when an interface, in this case the NB-PEI tie, is off schedule by an amount exceeding the normal or restricted transfer capability of the transmission corridor. This can occur when the PEI load, on-Island conventional generators, or wind generators are off schedule.

- Maritime Electric optimizes its energy costs on a daily basis by scheduling through the Energy Control Centre (ECC) where the least cost energy source is dispatched on an hour-by-hour basis, after ‘Take or Pay’ type contractual obligations are met (e.g. PEI Wind Farms; Point Lepreau).

IR-71 In response to **IR-18(a)**, MECL states that there may be generating capacity deficiencies in the region in 2027 while the Mactaquac restorative project is ongoing. Please advise how Maritime Electric plans to address the anticipated generating capacity deficiency and what efforts are being made to secure additional capacity prior to 2027.

Response:

The table below is an expanded capacity forecast that shows Maritime Electric's capacity situation to 2028:

Schedule of Planning Capacity Requirements and Resources											
	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
MECL capacity requirement (MW):											
- MECL peak load	244	256	265	266	272	282	284	290	301	303	309
- less interruptible load	14	14	14	14	14	14	14	14	14	14	14
- plus 15% planning reserve	34	36	37	37	38	39	39	40	41	41	42
Subtotal	**264**	**277**	**286**	**286**	**290**	**300**	**300**	**305**	**315**	**315**	**321**
MECL capacity resources (MW):											
- Charlottetown Thermal Plant	55	48	38	38	-	-	-	-	-	-	-
- Borden Plant	40	40	40	40	40	40	40	40	40	40	40
- Combustion Turbine 3	49	49	49	49	49	49	49	49	49	49	49
- Point Lepreau (at Murray Corner)	29	29	29	29	29	29	29	29	29	29	29
- Wind ELCC	21	21	24	24	24	24	24	24	24	24	24
- Short term capacity purchases[5]	80	105	110	110	145	145	-	-	-	-	-
- Incremental capacity required to avoid deficit[6]	-	-	-	-	10	15	160	165	175	175	180
Subtotal	**274**	**292**	**290**	**290**	**292**	**302**	**302**	**307**	**317**	**317**	**322**
Surplus (deficit)	**10**	**15**	**4**	**4**	**2**	**2**	**2**	**2**	**2**	**2**	**1**

In order to address capacity shortages, Maritime Electric can either a) procure additional generating capacity from mainland sources or b) build additional on-Island dispatchable generation that is capable of providing generating capacity.

Maritime Electric currently procures roughly one third of its capacity through short-term off-Island capacity purchases, and an additional 10 per cent from its participation in Point Lepreau. Maritime Electric will procure 53 per cent of its capacity via short-term capacity purchases upon closure of the CTGS in 2022. Without additional on-Island dispatchable generating capacity this is projected to increase to 56 per cent by 2028, bringing the total off-Island capacity supply to roughly two-thirds of the total. Maritime Electric's view is that having this level of generating capacity supply

5 Short-term capacity purchases currently under contract.
6 Maritime Electric assumes that it will procure the small amounts of required incremental capacity in 2022 and 2023 through short-term capacity purchases from off-Island sources.

exposed to transmission limitations or outages in New Brunswick may reach an unacceptable level of risk in the future.

Maritime Electric has been involved in regional transmission system discussions designed to upgrade the Atlantic region electrical interconnections. The Atlantic Energy Gateway project, a combined effort with Atlantic utilities and provincial governments with partial funding by NRCan, was undertaken in 2011-2012 in order to investigate non-emitting generation and transmission options in the Atlantic region. More recently, the Regional Electricity Cooperating and Strategic Infrastructure initiative, which started in 2017 and is ongoing, involves similar participants and is studying transmission solutions for various non-emitting generation scenarios in Atlantic Canada. An upgraded transmission link between New Brunswick and Nova Scotia would increase the NB-NS/PEI firm transmission transfer limit. This could increase the amount of firm transmission available to the Island, depending on the results of the mandatory open season for the incremental transmission capacity. As noted in IR-65, there is an upper limit on the amount of firm energy and capacity that can be imported to the Island from the mainland.

Maritime Electric has ongoing discussions with New Brunswick Power on new generating capacity sources in New Brunswick, and continues to monitor costs of building generation. In addition, Maritime Electric continues to review emerging and evolving technologies that may provide future capacity resources.

IR-72 With respect to the response to **IR-19(c)**, reference is made to possible rolling blackouts and shedding load. How is this reconciled with section 3 of the *Electric Power Act*, which requires a public utility to furnish reasonably safe and adequate service as changing conditions require?

Response:

Utilities have to balance system reliability versus the cost of service. The cost to ratepayers to ensure a complete backup of all Island customers at all load periods would be high. For discussion purposes, reliability of supply can be separated into two components – generation (also referred to resource adequacy) and delivery (the transmission and distribution systems).

For generation, reliability is a probabilistic concept. The reliability criterion followed by electric utilities in the northeastern United States and eastern Canada is that there will be no more than one day in ten years for which firm load has to be shed due to lack of generation supply (more specifically, this is the generation resource adequacy criterion followed by the Northeast Power Coordinating Council (NPCC), which covers the six New England states, New York State, Ontario, Quebec, and the Atlantic provinces). In order to be able to meet this level of reliability, utilities are required to have generating capacity in excess of the system peak load (also known as planning reserve). For example, Maritime Electric is required to maintain a planning reserve equal to at least 15 per cent of system firm peak load under its Interconnection Agreement with NB Power.

Maritime Electric also has to account for operating capacity, which refers to the amount of generation available at a given moment to supply the load. It looks at the real-time system and determines the load serving capability. Operating capacity levels vary depending on system conditions including outages and equipment derates (for seasonal, mechanical or electrical issues).

For delivery, Maritime Electric evaluates reliability in terms of the average number of hours that a customer is without power during a year. For the past ten years, the annual average customer outage has been almost 10 hours per year as can be seen below:

Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Average
SAIDI[7]	9.41	8.15	6.11	4.24	8.46	12.42	11.77	11.13	3.96	23.83	9.95

Load shedding and rolling blackouts deal with different real-time system issues. Load shedding is intended to be a short-term system option to avoid a system collapse. Load is shed – typically automatically but sometimes by an operator – to lessen the load on the system, allowing voltage to stabilize or rise slightly. Dispatchable generation is then brought online and the load is quickly restored.

Rolling blackouts are a measure of last resort – rotating energy supplies amongst customers to ensure they all receive energy for at least a portion of the day. They are rare events, intended to deal with supply constraints such as shortages of generation (a lack of operating capacity) or multiple transmission outages that constrain the flow of energy from generation to load. Maritime Electric has not had to initiate rolling blackouts in at least the last 20 years, and the Company's

[7] SAIDI all-in figures; includes major events

expanded interconnection with New Brunswick has afforded additional transmission redundancy between the mainland and the Island. The new facilities ensure that the Island can be completely supplied from off-Island even with the loss of one cable or one transmission line. This was not the case prior to the new interconnection being completed. In addition, there are three main supply lines feeding the Memramcook Substation – one 345 kV line and two 138 kV lines. The loss of multiple transmission elements typically occurs only during severe climatic conditions or rare major equipment failures in substations.

The storm on November 29, 2018 severed the energy supply from the mainland to the Island for almost seven hours. At the same time, Maritime Electric was experiencing on-Island transmission and distribution system outages. Had the mainland supply interruption lasted much longer and the on-Island system issues been significantly resolved, Maritime Electric would have likely commenced rolling blackouts.

IR-73 In response to **IR-22**, Maritime Electric states that once CTGS is decommissioned, Maritime Electric will be obtaining 60% of its generating capacity from off-Island sources through a single transmission corridor. Maritime Electric also states that additional on-Island diesel-fired combustion turbine generation would reduce the impact of a loss of the transmission corridor. In 2015, Maritime Electric submitted an application to the Commission seeking approval to purchase a 50 MW combustion turbine (Commission Docket UE20723). This application was ultimately withdrawn by MECL as it had procured access to 50 MW of firm capacity.

a. How much of MECL's annual generating capacity from off-Island sources was obtained through the single transmission corridor in each of 2014 to present?

b. If on-Island diesel-fired combustion turbine generation would reduce the impact of a loss of the transmission corridor, please explain why MECL withdrew its combustion turbine application in UE20723?

c. Has MECL considered other alternatives to installing a new combustion turbine, such as installing utility-scale batteries at the CTGS site? If so, please provide full particulars of the alternatives considered.

d. What is the likelihood of losing the transmission corridor in its entirety, and how often has the transmission corridor been lost in the last 20 years?

e. Is the loss of the transmission corridor in its entirety considered an N-1 transmission event or an N-2 transmission event?

f. Does good utility practice require MECL to provide capacity support for the loss of the transmission corridor?

g. Do FERC, NERC or NPCC standards or guidelines require MECL to provide capacity support for the loss of the transmission corridor?

h. Has MECL had discussions with New Brunswick Power and/or New Brunswick Energy Marketing Corporation regarding improvements to the New Brunswick transmission system to minimize the effects of the loss of the transmission corridor? If so, please provide full particulars.

Response:

The term 'transmission corridor' in this response to questions 73 a)-h) refers to the three 138 kV lines (L1142, L1143 and L1244) and associated four 138 kV submarine cables that connect the Memramcook Substation in New Brunswick to the Richmond Cove Riser Station and Borden Riser Station in PEI, as can be seen in the diagram attached in IR-73 – Attachment 1.

a.

	2014	2015	2016	2017	2018
Maritime Electric capacity resources (MW):					
- Charlottetown Thermal Plant	60	60	58	55	55
- Borden Plant	40	40	40	40	40
- Combustion Turbine 3	49	49	49	49	49
- Point Lepreau (at Murray Corner)	29	29	29	29	29
- Wind ELCC	21	21	21	21	21
- Short term capacity purchases	40	57	55	70	95
Subtotal	239	256	252	264	289
Capacity from on-Island sources	170	170	168	165	165
Capacity from off-Island sources	69	86	84	99	124

b. The New Brunswick System Operator ('NBSO') informed Maritime Electric in 2011 that there was no additional firm transmission on the existing system available above Maritime Electric's existing 80 MW reservation. This limited Maritime Electric's access to off-Island firm energy and generating to 80 MW. In response to increasing load, Maritime Electric applied to the NBSO in 2013, through NB Energy Marketing ('NBEM'), for an additional 50 MW of firm transfer capacity across the NB-NS/PEI interface. Maritime Electric had not received a response by early 2015 to this request, and proceeded to submit an application to the Commission in June 2015 under Docket UE20723 for an additional on-Island combustion turbine ('CT4'). The two primary drivers for additional on-Island capacity were to: a) help mitigate the risk to energy supply of transmission system constraints in New Brunswick, as the firm transfer across the NB-NS/PEI interface was limited to 80 MW; and b) replace the CTGS generating capacity that was nearing its end of life.

Maritime Electric was informed in January 2016 that the 50 MW of firm transfer capacity would be awarded to Maritime Electric after upgrades to the New Brunswick transmission system, and an additional 70 MW of firm transfer capacity across the NB-NS/PEI interface would be available during an open season later in 2016. As a result of the interface's increased transfer capability – Maritime Electric intended to pursue the 70 MW available in the open season – Maritime Electric chose to withdraw its application in late January 2016 as the increased transmission capacity in New Brunswick meant that there was no longer a requirement for the on-Island capacity provided by CT4.

c. PEI has limited options for on-Island generating capacity due to its lack of natural resources. Most generating capacity resources are available from off-Island. Maritime Electric has not undertaken a detailed business case examination of utility-scale batteries, primarily due to their cost and limited storage capacity. The average cost of long-duration (greater than 2 hours of storage) battery capacity in 2017 was US$2,430 per kW[8], or CAD$3,250 per kW. 50 MW of long-term battery storage would cost in excess of CAD$160M. A similar-sized combustion turbine, with much more inherent 'storage' (in the

[8] U.S. Energy Information Administration, U.S. Battery Storage Market Trends, May 2018

form of fuel supplies), would cost less than half that amount. Battery storage is not yet to the point where it is economic on the large scale that Maritime Electric requires. Maritime Electric has also investigated compressed air storage. It is currently being done in small-scale installations, but none of a size comparable to a combustion turbine. Underground compressed air storage is best suited to locations with existing salt caverns or other porous rock (such as depleted gas fields). PEI has neither. Underwater storage using deflatable air bags is also a consideration in some locations but PEI does not have sufficient water depth close to shore to make this feasible.

d. The transmission corridor has been lost once in the past 20 years. During the 2004 Memramcook substation expansion project one transmission line, under heavy loading, sagged into another line and caused an outage. This clearance issue was resolved and there have been no further issues on the corridor between Memramcook and Murray Corner/Cape Tormentine.

The November 29, 2018 storm caused a loss of transmission lines between Memramcook and Salisbury/Moncton which cut the supply to Nova Scotia and PEI. Only one line between Memramcook and the Island was lost during that storm. The likelihood of loss of all three lines between Memramcook and the Island is low, and it is caused by rare occurrences such as: a) intentional damage; b) a lighting storm severe enough to damage line equipment on all three lines; c) a severe ice storm; or d) a tornado or hurricane-force winds.

e. The ‘1’ in N-1 refers to a single transmission element. The ‘2’ in N-2 refers to a single event that instantaneously takes out two transmission lines, such as a contingency that removes both lines on a double circuit tower or parallel transmission lines whose outer and adjoining conductors make contact. In the case of the transmission corridor between Memramcook and the Island, there are three separate overhead lines, and the most likely case of a forced outage of the entire corridor is N-1-1-1, where the climatic or loading conditions force an outage on one line at a time.

f. Good utility practice suggests that Maritime Electric has a plan in place, and provides a reasonable amount of operating capacity support. Maritime Electric has seven days of fuel storage on-site at both Borden and Charlottetown, and has a preliminary investigation into the amount of wind that can operate in the event of a loss of supply from the mainland.

Maritime Electric is also updating its rolling blackout procedures to ensure that all customers receive energy for at least a portion of the time before the mainland connection can be re-established. Maritime Electric is assuming that at least one of the lines in the transmission corridor could be reconstituted within two to three days, which would re-establish connection to the mainland. While the transmission corridor is not roadside, there are multiple access roads along its length and its vegetation is managed regularly. Deeper system issues, such as a loss of 345 kV between Saint John and Memramcook, may take longer to resolve.

g. There are no FERC, NERC or NPCC standards or guidelines that require Maritime Electric to provide capacity support for the loss of the transmission corridor. NERC and NPCC standards and guidelines cover issues such as resource adequacy, load response, and transmission system planning on a regional basis, not on a local basis. NERC and NPCC put standards and guidelines in place to ensure that each region has sufficient resources internally or under contract (via interconnections) to provide reliable service, and that system events do not cascade between regions.

Maritime Electric is part of the Maritimes region, which includes New Brunswick, Nova Scotia, and parts of northern Maine. In the event of the loss of the transmission corridor, from NPCC's perspective as long as the Maritimes region remains stable and its issues do not cascade into adjoining regions, then NPCC criteria has been met. The loss of supply to the Island would be considered a local issue.

h. Maritime Electric has been involved in regional transmission system discussions designed to upgrade the Atlantic region electrical interconnections. The Atlantic Energy Gateway project, a combined effort with Atlantic utilities and provincial governments with partial funding by NRCan, was undertaken in 2011-2012 in order to investigate non-emitting generation and transmission options in the Atlantic region. More recently, the Regional Electricity Cooperating and Strategic Infrastructure initiative, which started in 2017 and is ongoing, involves similar participants and is studying transmission solutions for various non-emitting generation scenarios in Atlantic Canada. An upgraded transmission link between New Brunswick and Nova Scotia would increase the NB-NS/PEI firm transmission transfer limit. This could increase the amount of firm transmission available to the Island, depending on the results of the mandatory open season for the incremental transmission capacity.

Maritime Electric has ongoing discussions with New Brunswick Power on new generating capacity sources in New Brunswick, and continues to monitor costs of building generation. In addition, Maritime Electric continues to review emerging and evolving technologies that may provide future capacity resources.

IR-74 With respect to the response to **IR-24**, please provide specific reference to all relevant provisions of the Energy Purchase Agreement.

Response:

The response to IR-24 has been included below in its entirety. The references to the relevant provisions of the Energy Purchase Agreement ('EPA') have been added, and are shown *underlined and italicized*:

The new Energy Purchase Agreement (March 1, 2019 – February 29, 2024) provides for an Assured Energy product of up to 50 MWh/h that is backed-up by capacity. *(Assured Energy is defined in Part 1 - Definitions under Section 1.2 'Assured Energy' on page 3 of the EPA).* Assured Energy is energy for which the pricing can be changed after the provision of written notification to Maritime Electric from NB Energy Marketing. The notification specifies a period of time after which the Assured Energy can be Interrupted or Curtailed on ten minutes' notice. *Notification and Notification Period are defined in Part 1 - Definitions under Section 1.20 'Notification' and Section 1.21 'Notification Period' on page 5 of the EPA. The clause that covers "Assured Energy" is Section 4.3 (subsections a through h) on pages 15, 16 and 17).*

The Assured Energy product is intended to minimize the operation of Maritime Electric's generating resources while Maritime Electric provides backup using Maritime Electric's available operable capacity *(as noted in Section 4.1 (b) and (d) 'Nature of Service' on page 11 of the EPA).*

The Assured Energy product is backed-up as follows:

- Summer Period (as defined in Section 1.27 on page 6 of the EPA) – during the Summer Period the Assured Energy product is capacity backed under contract with NB Energy Marketing (NBEM) during the first 90 days of the Notification Period then backed by the CTGS if the event continues beyond the 90 days. The 90 days is referenced under Section 1.21 'Notification Period' on page 5 of the EPA.

- Winter Period (as defined in Section 1.31 on page 6 of the EPA) - during the Winter Period the Assured Energy product is capacity backed by the Borden Generating Station (BGS) during the first 90 days of the Notification Period and then by the CTGS if the event continues beyond the 90 days. During the "Winter Period" Maritime Electric will purchase 10 Minute and 30 Minute Supplementary Non-Spinning Reserve from the NBP-System Operator.

The longer return to service period of 90 days is due to the longer time frame that would be required to remove steam boilers and steam turbines from long-term layup in preparation for operation. The 90 day return to service period also accommodates a reduced compliment of CTGS operating staff. Many CTGS operating staff employees have been re-trained and have been redeployed to other Maritime Electric departments in order to more efficiently utilize these labour resources until such time as the completion of the CTGS decommissioning project proposed for 2022/2023. The 90 day period will provide Maritime Electric management with enough time to bring these redeployed staff back to the CTGS, to temporarily backfill their positions in the other Maritime Electric departments and to provide refresher safety and operations training for the staff returning to operate the Steam Plant.

IR-75 In response to **IR-24**, MECL states that CTGS is subject to a 90 day return to service requirement under the Energy Purchase Agreement. However, in response to **IR-32**, MECL states that under the terms of the Energy Purchase Agreement, CTGS is scheduled for closure by January 1, 2022, with planned decommissioning in 2022 and 2023. Please explain how CTGS will be available for 90 day return to service if it is scheduled to be closed and decommissioned during the period of the Energy Purchase Agreement.

Response:

The response provided in IR-24 refers to the requirement for the Charlottetown Thermal Generating Station (CTGS) to return to service within a 90-day timeframe on a go forward basis. This only applies during the first few years of the Energy Purchase Agreement (EPA) from the contract's effective date of March 1, 2019 until the proposed closure date of the CTGS which is January 1, 2022 as noted in the response to IR-32.

Within the EPA Maritime Electric has made contractual arrangements to purchase additional generating capacity from New Brunswick Energy Marketing from January 1, 2022 until the expiry date of the EPA on February 29, 2024 as per the table below.

The schedule of Firm Capacity included in the EPA is as follows:

		Firm Capacity Requirement at Time of EPA Signing	Firm Capacity Requirement Current Forecast[9]
March 1, 2019	December 31, 2019	95 MW	105 MW
January 1, 2020	December 31, 2020	95 MW	120 MW
January 1, 2021	December 31, 2021	95 MW	125 MW
January 1, 2022	December 31, 2022	130 MW	160 MW
January 1, 2023	December 31, 2023	130 MW	160 MW
January 1, 2024	February 29, 2024	130 MW	160 MW

The step change in Firm Capacity Requirements between 2021 and 2022 shown in the table above indicates that NB Energy Marketing will be providing additional generating capacity to Maritime Electric to accommodate the decommissioning of the Charlottetown Thermal Generating Station which will have 40 MW of generating capacity in late 2021.

[9] Load has increased at a rate higher than forecast at the time of EPA signing, requiring the Company to procure additional capacity supplies.

IR-76 In the response to **IR-26**, reference is made to **IR-26 – Attachment 1**. This attachment has not been filed with the Commission. Please provide a copy of **IR-26 – Attachment 1**.

Response:

This attachment has been provided as IR-76 – Attachment 1 to this response.

IR-77 In response to **IR-28**, MECL states that the recovery of DSM expenditures through ECAM is based upon past Orders UE08-02 and UE15-02. Notwithstanding previous Orders, please provide justification for the continued recovery of DSM expenditures through ECAM during the period of the proposed General Rate Application.

Response:

Maritime Electric's response to IR-28 states in part, "Order UE15-02 in particular relates to the current DSM costs relating to the Company's annual public outreach and education programming." Since these activities relate to promoting the efficient use of electricity, it can be argued that these are energy related costs and therefore relevant for inclusion in ECAM.

Under Order UE15-02, Community Outreach program spending of approximately $167,000 per year, amortized in the year following, was approved for each of the five years 2016 to 2020. Order UE15-02 was in response to Maritime Electric's June 2015 application to the Commission for approval of a five year Energy Efficiency and Demand Side Management Plan, of which the Community Outreach program was a small component. As part of the Plan, the Company proposed that the costs incurred would be amortized over time periods that would match the multi-year time periods over which the benefits of the Plan would be realized. The Company also proposed that the amortized costs would be recovered through the Energy Cost Adjustment Mechanism (ECAM). Recovery through ECAM would provide flexibility given the expected variability in the timing and amounts of costs to be recovered.

The Commission approved only the Community Outreach component of the Plan. Given the dollar amounts involved, the Company does not see a compelling reason to recover these costs through ECAM notwithstanding the current requirement of Order UE15-02 to amortize such costs to ECAM until 2021 (the amortization of the final 2020 year Community Outreach expenditures). However, inclusion of energy efficiency and DSM costs for recovery through ECAM does provide flexibility for lumpy costs such as program development or the ability to respond to opportunities that may arise to partner with other organizations.

IR-78 In response to **IR-37**, MECL states that "*The other recommendations in the Gannett Fleming Study will be reviewed as part of future depreciation study updates and addressed in further applications to the Commission*":

a. Please advise what the "*other recommendations*" are.

b. Please explain why the other recommendations are not included as part of the current General Rate Application, and provide justification for same.

c. Please provide a table of rates showing the rates for each class of customers if all recommendations in the Gannett Fleming Study are implemented as part of the current General Rate Application.

Response:

a. The other recommendations refer to the Company's proposal to defer amortization of the accumulated reserve variance on all other asset classes (except the CTGS) as outlined Section 11.4.2(ii) of the GRA evidence. In particular, this refers to the annual reserve variance amortization recommended by Gannett Fleming in Schedule 11-3 and summarized below:

Asset Class	Recommended Annual Amortization ($ Millions)
Production Plant	
▪ Border Generating Station	0.235
▪ Combustion Turbine #3	0.054
Transmission Plant	(0.049)
Distribution Plant	1.090
General Plant	0.083
Total	**1.413**

b. As noted in Section 11.4 of the GRA evidence, the Company recognizes that fully adopting the Gannett Fleming 2017 Depreciation Study recommendations in total would result in a further increase in depreciation expense to be recovered from customers.

In addition, the Gannett Fleming 2017 Depreciation Study notes on Page I-5:

"The calculated accrued depreciation is used as a measure to assess the adequacy of the Company's book accumulated depreciation amount. The calculated accrued depreciation should not be viewed in exact terms as the correct reserve amount. Rather it should be viewed as a benchmark or a tool used by the depreciation professional to assess the standing of the book accumulated depreciation amount based on the most recent available information."

The Company concurs with Gannett Fleming's comments and, therefore, proposes to adopt the recommended new depreciation rates and address the amortization of the accumulated reserve variance for the CTGS while deferring amortization of the accumulated reserve balance on other assets until a future Depreciation Study. It is the Company's position that this approach will strike a reasonable balance between changes to depreciation and the potential material impact of all changes on customer electricity rates.

Since 2016 (Commission Order UE16-04), the Company has applied the recommended annual depreciation rates from the Gannett Fleming depreciation study and has begun to amortize the accumulated reserve variance for the CTGS while continuing to monitor the residual accumulated reserve variance on all other assets. Future depreciation studies will enable further assessment of estimated accumulated reserve variance balances and assist the Company and the Commission in developing balanced solutions to address its recovery over a reasonable timeframe.

c. The Commission's interrogatory IR-37 specifically identified the accumulated reserve variance on the Distribution Plant. In the response to IR-37, the Company indicated that based on annual electricity sales of $195 million, an increase of $1.090 million in annual depreciation to recover the accumulated variance on the distribution plant would result in a one-time annual increase in the Company's revenue requirement and resulting customer electricity costs of approximately 0.6 per cent.

As noted in the response to part (a) above, the total annual reserve variance amortization calculated by Gannet Fleming for all other assets in Schedule 11-3 (excluding the CTGS) is $1.413 million. Based on annual electricity sales of $195 million, an increase of $1.413 million in annual depreciation would result in a one-time annual increase in the Company's revenue requirement and resulting customer electricity costs of approximativelу 0.7 per cent.

Consistent with the proposals in the GRA to set customer electricity rates to provide stable adjustments over the three year period, the following table shows the percentage annual customer electricity cost increase (before tax) for the typical customer in each rate class if all of the recommendations proposed by Gannett Fleming were included in the proposed rates:

Impact of Including the Total Annual Reserve Variance Recommended by Gannet Fleming in the Rates Proposed in the GRA		
March 1, 2019	**March 1, 2020**	**March 1, 2021**
1.4%	1.4%	1.4%

Note: The rate impact for the average Rural Residential customer in 2019 will be -0.6% as a result of the proposed decrease in the Residential Service Charge to that of the Urban Service Charge in 2019.

An updated Appendix 2 to the GRA, Section N-28 – Schedule of Proposed Rates March 1, 2019 to February 28, 2022 to reflect the impact of including all recommendations in the Gannett Fleming Study is provided as IR-78 - Attachment 1 to this response.

IR-79 In response to **IR-37**, MECL states that the required increase in the revenue requirement to amortize the deferred variance related to the distribution plant "*would result in a one-time annual increase in the Company's revenue requirement and resulting customer electricity costs of approximately .06%."*

a. However, by not addressing this variance when identified, does it not cause a larger increase for ratepayers in future years?

b. Please provide an explanation as to why deferring this variance to future years and future ratepayers is the appropriate treatment of the variance.

Response:

a. The Company has proposed to undertake a new Depreciation Study based upon financial results up to December 31, 2020. This study will be used to develop recommendations on the establishment of new depreciation rates as well as the amortization of the calculated accumulated reserve variance for the various asset classes at that time. The impact of these proposals on customers at that time will be dependent upon the calculated accumulated reserve variance and the proposed period over which it is to be amortized.

As noted in response IR-78(b), Gannett Fleming advises that the calculated accrued depreciation should not be viewed in exact terms as the correct reserve amount. Rather it should be viewed as a benchmark or tool used by the depreciation professional to assess the standing of the book accumulated depreciation amount based on the most recent available information.

Gannett Fleming's statement acknowledges that the calculation of the accumulated reserve variance is an estimate at a point in time and will vary from study to study as a result of a number of factors used in previously setting depreciation rates. These factors include variances between actual and projected asset additions and retirement patterns as well as service life and net salvage estimates.

Since these factors may result in the accumulated reserve variance balance either increasing or decreasing at the time the next depreciation study is conducted, the Company is unable to comment on whether the future amortization will be larger or smaller. However, assuming all of the assumptions in the most recent Gannet Fleming study are correct until the next study and assuming the Commission approves the proposed new depreciation rates in the GRA, the accumulated reserve variance for all other assets would remain the same as calculated in the 2017 Study.

b. Refer to the response to IR-78(b)

IR-80 In response to **IR-38**, is it correct to conclude that MECL has no additional net tax burden resulting from the transfer to MECL of Part VI.1 tax payable by Fortis Inc., and that the ratepayers of MECL pay no additional amounts as a result of the Part VI.1 tax transfer?

Response:

This is correct.

IR-81 The proposals contained in the General Rate Application are based on the assumption that the proposed rates would be implemented effective March 1, 2019. Please provide a schedule showing the impact on the proposed rates assuming new rates are implemented effective July 1, 2019, August 1, 2019, September 1, 2019, and October 1, 2019.

Response:

The proposals in the GRA to set customer electricity rate adjustments effective March 1, 2019 encompass all factors effecting customer electricity costs and were developed to provide stable adjustments over the three year period such that the typical customer in each rate class would see a 1.1 per cent per year increase. Changes to the implementation date for rate adjustments to a month later than March 1 affects not only the recovery of the Company's annual revenue requirement but also the balances to be recovered or refunded through regulatory deferral accounts such as ECAM and RORA as well as the rider rates for those costs recoverable on behalf of the Province.

In response to Multeese IR-69(b), Maritime Electric provided tables to show the composition of the various components of the total energy charge per kWh for each rate class as proposed in Schedule 15-1 of the GRA. Comparable tables are included with this response as IR-81 – Attachment 1 showing the impact where rate adjustments are implemented July 1, 2019, August 1, 2019, September 1, 2019 and October 1, 2019 to achieve stable customer electricity costs adjustments over the 2019-2021 period.

The following table shows the percentage annual customer electricity cost increase (before tax) for the typical customer in each rate class as compared to the GRA March 1, 2019 proposed adjustment date.

Impact of 2019 Implementation Date Change on Customer Electricity Costs			
2019 Implementation Date	**2019**	**March 1, 2020**	**March 1, 2021**
March 1, 2019 (GRA)	1.1	1.1	1.1
July 1, 2019	1.2	1.2	1.2
August 1, 2019	1.2	1.2	1.2
September 1, 2019	1.3	1.3	1.3
October 1, 2019	1.3	1.3	1.3

Note: The impact will vary from above for the average Rural Residential customer as a result of the decrease in the Residential Service Charge in 2019 on the proposed implementation date.

The following refer to MECL's responses to the interrogatories of Synapse Energy Economics, Inc.:

IR-82 In response to **IR-1 filed by Synapse Energy Economics, Inc.**, MECL states that a Life Extension Program was undertaken with respect to the CTGS in the early 1990s. At the time of the Life Extension Program in the 1990s, what was the estimated life of the CTGS plant?

Response:

The Life Extension Program (LEP) was undertaken in the 1990 to 1995 timeframe. The goal of the LEP was to extend the life of the equipment at the Charlottetown Thermal Generating Station (CTGS) for an additional 15 years from 1995 to 2010.

In addition to the LEP, Maritime Electric's ongoing maintenance practices coupled with intermittent operation enabled the extension of the equipment operating life (see Table 1 below). However, the CTGS equipment is approaching the end of its useful life as evidenced in earlier filings with the Commission. The Company minimizes expenditures to maintain the equipment availability from a safety and reliability perspective (ie. large capital expenditures are not being made to further extend the equipment life).

Table 1
CTGS Turbine Operating Hours 2010-2018

TOTALS	**1,491**	**1,547**	**124**	**99**	**4**
Year	**#10 Turbine**	**#9 Turbine**	**#8 Turbine**	**#7 Turbine**	**#6 Turbine**
2018	-	-	-	-	-
2017	72	131	29	29	**Removed**
2016	77	93	52	-	-
2015	174	266	15	3	-
2014	145	239	11	19	-
2013	130	99	3	4	-
2012	651	509	-	27	-
2011	172	136	15	17	2
2010	70	74	-	-	2

IR-83 In response to **IR-1 filed by Synapse Energy Economics, Inc.**, MECL states that it is standard utility generation practice to complete a major overhaul of turbine-generator sets every ten years.

a. What major overhauls have been done at the CTGS plant since the 1990s?

b. What changes have been made in the depreciation rates for CTGS since the completion of the Life Extension Program in the 1990s?

c. Explain the rationale for any changes, or lack of changes, in depreciation rates between 1990 and present.

Response:

a. Maritime Electric accomplished a major overhaul of each of its generating units at the Charlottetown Thermal Generating Station (CTGS) during the Life Extension Program completed over the time period of 1990 to 1995. The costs of the refurbishment work undertaken during the Program were approximately $27 Million in 1995 Canadian Dollars.

A list of reports on major refurbishments completed on each of the units since 1990 as provided in the response to Multeese Consulting Interrogatory IR-5 (c) is provided below. Maritime Electric does not have detailed records that reflect major refurbishments that occurred prior to 1990.

Table 3
Installation and Recent Significant Maintenance Dates on Major Units at CTGS

Unit	Activity	Date
Turbine – Generator 7	Installation Life Extension Program Turbine Blade Inspection	1956 1994 2001
Turbine – Generator 8	Installation Life Extension Program Turbine Blade Inspection Overhaul Rewedge Generator Stator	1960 1991 2001 2006 2006
Turbine – Generator 9	Installation Life Extension Program Turbine Blade Inspection Overhaul Rewedge Generator Stator	1963 1990, 1993 2001 2002 2005
Turbine – Generator 10	Installation Life Extension Program Turbine Blade Inspection Overhaul Rewedge Generator Stator	1968 1991 2001 2004 2005
Boiler 2	Installation New Burner	1997 2005
Boiler 4	Installation Significant Refurbishment	1954 1992
Boiler 5	Installation Significant Refurbishment New Burners	1960 1991 2007-2008
Boiler 6	Installation	1976
Boiler 9	Installation Significant Refurbishment Boiler Rebuilt	1963 1990 1995
Boiler 10	Installation Significant Refurbishment Install T-Jet Burners	1968 1991 2007

b. The Life Extension Program at the CTGS was substantially completed by 1995. The following schedule shows the depreciation rates applied to the CTGS assets from 1995 to present.

Year	Depreciation Rate (%)
1995 - 2015	2.50
2016 - 2018	7.99
2019 - Present	5.09[10]

c. Until April 30, 1994, Maritime Electric was regulated under cost of service regulation with depreciation rates for the Company's fixed assets set by the regulator. In 1994, the CTGS assets were depreciated at a rate of 3.0 per cent. Upon completion of the Life Extension Program in 1995 and in recognition of the change in the role of the CTGS to that of back-up, the depreciation rate was reduced to 2.50 per cent where it remained in place until December 31, 2015.

Between May 1, 1994 and December 31, 2003 the Company operated in a price cap environment in accordance with the provisions of the Maritime Electric Company Limited Regulation Act. On January 1, 2004, the Company returned to cost of service regulation by IRAC under the terms and provisions of the Electric Power Act.

On April 6, 2006 the Commission ordered (UE06-02) that the Company file a Depreciation Study by August 31, 2006. On August 31, 2006 the Company filed a Depreciation Study prepared by Gannett Fleming based on 2005 financial results ("the 2005 Study"). The Commission ordered (UE07-01) on March 1, 2007 that the current rates of depreciation of the Company shall remain in effect until otherwise ordered by the Commission and that a further Depreciation Study be filed with the Commission within 36 months of the date of the order.

In January 2006, the Accounting Standards Board announced its decision to require all Publicly Accountable Enterprises ("PAE") to report under International Financial Reporting Standards ("IFRS") for years beginning on or after January 1, 2011. The change from Canadian Generally Accepted Accounting Principles ("GAAP") to IFRS would apply to all PAE which includes listed companies and any other organizations that are responsible to large or diverse groups of stakeholders, including non-listed financial institutions, securities dealers and many co-operative enterprises. While Maritime Electric was not, and is not, a PAE, it would be required to adopt these standards in its reporting to its parent Fortis Inc. which was to take effect January 1, 2011.

Subsequently, the Company advised the Commission of the impending changes announced by the Accounting Standards Board and that the appropriate methodology (the Equal Life Group Methodology or the Average Service Life Methodology) for purposes of undertaking a Depreciation Study, for those companies adopting IFRS, had not been determined.

[10] As outlined in Appendix II of the GRA evidence, it is proposed that the accumulated reserve variance be amortized as a separate regulatory deferral account in the amount of $3.249 million per year. Including this amortization amount yields an annual effective depreciation rate for 2019 onward of 10.43% (Appendix II: [3,088,455 + 3,249,029)/60,749,618])

On May 8, 2008 the Commission ordered (UE08-07) Maritime Electric to defer completion of the Depreciation Study required under Order UE07-01 until further ordered by the Commission and that Maritime Electric provide quarterly updates to the Commission on the progress of the transition to IFRS.

On December 9, 2010, the Provincial Government enacted the Electric Power (Electricity Rate Reduction) Amendment Act, (S.P.E.I. 2010, c. 9) and on December 7, 2012, the Provincial Government enacted the Electric Power (Energy Accord Continuation) Amendment Act, (S.P.E.I. 2012, c. 6). These two pieces of legislation established a period between March 1, 2011 and February 29, 2016, collectively referred to as the PEI Energy Accord, which among other things established input factors for the years 2011-2015, including depreciation, and fixed the rates, tolls and charges of Maritime Electric.

On January 1, 2012 Fortis Inc. adopted U.S. GAAP as its financial reporting standard and Maritime Electric, effective January 1, 2011, adopted Canadian Accounting Standards for Private Enterprises (ASPE) and chose to apply the Average Service Life Methodology of depreciation as recommended by Gannett Fleming.

Recognizing the PEI Energy Accord's end on February 29, 2016, and the Company's return to cost of service regulation for purpose of rate setting effective March 1, 2016, the Company engaged Gannett Fleming to prepare the 2014 Depreciation Study based upon financial results up to and including December 31, 2014.

The 2014 Study was prepared in support of recommended changes to depreciation rates to be adopted in 2016 and used in calculating depreciation expense for purposes of determining customer electricity rate adjustments commencing March 1, 2016.

Upon consideration of the 2014 Depreciation Study results, which together would have resulted in a significant increase in depreciation expense, the Company proposed to adopt the recommended depreciation rates in the 2014 Study but defer the amortization of the accumulated reserve variance on all asset classes except for the CTGS. The Company believed that these proposals struck a reasonable balance between the impact on customer electricity costs from higher depreciation expense and the need to fully depreciate the CTGS assets prior to the facility's closure and decommissioning.

The Company's General Rate Application, filed on October 21, 2015, and the subsequent General Rate Agreement filed with the Commission for approval on February 5, 2016 incorporated the proposed new depreciation rates and amortization of the accumulated reserve variance related to the CTGS as outlined above. On February 29, 2016, IRAC issued Order UE16-04 approving the Company's proposals for the depreciation rates which established a new depreciation rate effective January 1, 2016 for the CTGS of 7.99 per cent (comprised of depreciation – 4.53 per cent and accumulated reserve variance amortization – 3.46 per cent).

The Company proposes to modify this rate effective January 1, 2019 as outlined in response IR-83(b) above.

<u>The following refer to MECL's responses to the interrogatories of Multeese Consulting Inc.:</u>

IR-84 In response to **IR-55 filed by Multeese Consulting Inc.**, MECL states that NB-NS/PEI interface firm transfer capability is currently limited to 300 MW due to "limiting elements" located on the New Brunswick transmission system. MECL also states that the Island's peak load is forecast to surpass 300 MW by 2023.

a. What are the "limiting elements" on the New Brunswick transmission system?

b. Please provide full details of any and all discussions with NBP and/or NBEM to address these limiting elements.

c. Please provide full particulars of MECL's plan to address the limits at the NB-NS/PEI interface prior to 2023.

d. In the event NBP and/or NBEM is not prepared to address the limiting elements, how does MECL plan to deal with the anticipated capacity shortfall?

Response:

a. Maritime Electric understands from NB Power that the existing limiting element on the NB transmission system is the 345 kV line denoted '3004' between the Coleson Cove and Norton substations in southwestern New Brunswick. Loss of this line forces more west to east flows onto the underlying 138 kV system. It is the thermal limitations on these underlying 138 kV lines that directly contribute to the 300 MW limitation across the NB-NS/PEI interface.

b. Please see response to IR-73 (h).

c. Maritime Electric has 270 MW[11] of firm transmission capacity across the NB-NS/PEI interface until the end of its current EPA (February 29, 2024). The Company has 300 MW of planning capacity obligations in 2023, as detailed in IR-65(a), of which 189 MW will be procured from off-Island (short-term purchases plus Pt. Lepreau) in 2023. Thus the NB-NS/PEI interface does not limit Maritime Electric's access to planning capacity in the near term.

However, when considering generating capacity Maritime Electric has to address two kinds – planning and operational. Operational capacity refers to how much generation is available at a given moment for load supply. In the absence of wind and with the CTGS decommissioned, the following on-Island generation will be available to Maritime Electric:

[11] Based nominally on a 300 MW NB-NS/PEI interface capacity, with Maritime Electric having 90% of Island load and Summerside accounting for 10% of Island load

Unit	Winter Capacity (MW)	Summer Capacity[12] (MW)	Year Installed
Charlottetown CT3	49	35	2005
Borden CT1	15	12	1971
Borden CT2	25	18	1973
Total	**89**	**65**	

The NB-NS/PEI interface allows the Company to supply 359 MW of load via firm transfer capacity plus on-Island dispatchable generation as seen below:

Maritime Electric nominal portion of PEI Transfer Limit	270 MW
Maritime Electric on-Island dispatchable generation (CT3 + Borden)	89 MW[13]
Total Maritime Electric load serving capability (includes interruptible load)	359 MW[14]

Maritime Electric's peak load forecast in 2023 is 282 MW, meaning that the Company has a sufficient combination of off-Island transmission and on-Island generation resources to supply its 2023 peak load under normal system operating conditions.

Even though the Company has 270 MW of firm transmission capacity on the NB-NS/PEI interface, there is no guarantee it can be delivered all the time. In 2018 alone there were two instances where there was insufficient capacity across the NB-NS/PEI interface, even though none of these two involved the transmission corridor between Memramcook and Murray Corner/Cape Tormentine:

- January 22 – the interface was limited to 100 MW due to 138 kV line issues near Moncton. Maritime Electric was required to purchase emergency capacity from NS Power (which often doesn't have surplus capacity available).
- November 29 – a winter storm caused trips on two of the transmission lines supplying the Memramcook substation from Salisbury/Moncton, causing the third supply line to thermally overload and trip. A supply link to the mainland was not reinstated for over seven hours.

The Company can have sufficient planning capacity under contract, but may experience, on occasion, a shortage in operating capacity conditions due to a historically infrequent mainland supply constraint.

d. The Company may be able to purchase additional interruptible energy supply – backstopped by on-Island generation sources – above the 270 MW level (300 MW when considering both Maritime Electric and Summerside). However, Maritime Electric does not

12 The summer capacity is lower than winter capacity, as summer air – with its higher ambient air temperature – is lower density than winter air (with its colder ambient air temperature). As air density increases, generators output more power per unit of fuel input.
13 Winter rating of generation
14 Maritime Electric's portion of the NB-NS/PEI interface plus Maritime Electric on-Island dispatchable generation, excludes wind generation

know at this time what would be required to increase the NB-NS/PEI interface firm transfer capability above the 300 MW level. Thermal, voltage, and system stability issues all have to be taken into account. The Company intends to engage NB Power to determine with greater clarity the mainland system's existing condition, limitations and potential upgrades, and their impacts on quantity and reliability of supply to the Island.

Furthermore, the impact on the Island system of mainland imports in excess of 300 MW has not been studied in detail, and the Company will initiate a detailed study of the Island transmission system to determine its capabilities under high import situations.

The Company will investigate the use of transmission, generation and peak load management techniques – such as direct load control or use of smart meters combined with time of use rates – in order to accommodate its growing peak load and high import situations. Peak load management techniques serve to delay, although often not completely avoid, the additional infrastructure required to supply a growing load. Preferred solutions will be presented and pursued through the rate setting process.

In the near term, existing dispatchable on-Island generation will be used to supply the load in excess of the 300 MW import limit when wind generation is insufficient.

INTERROGATORIES

Section IR-64

ATTACHMENT

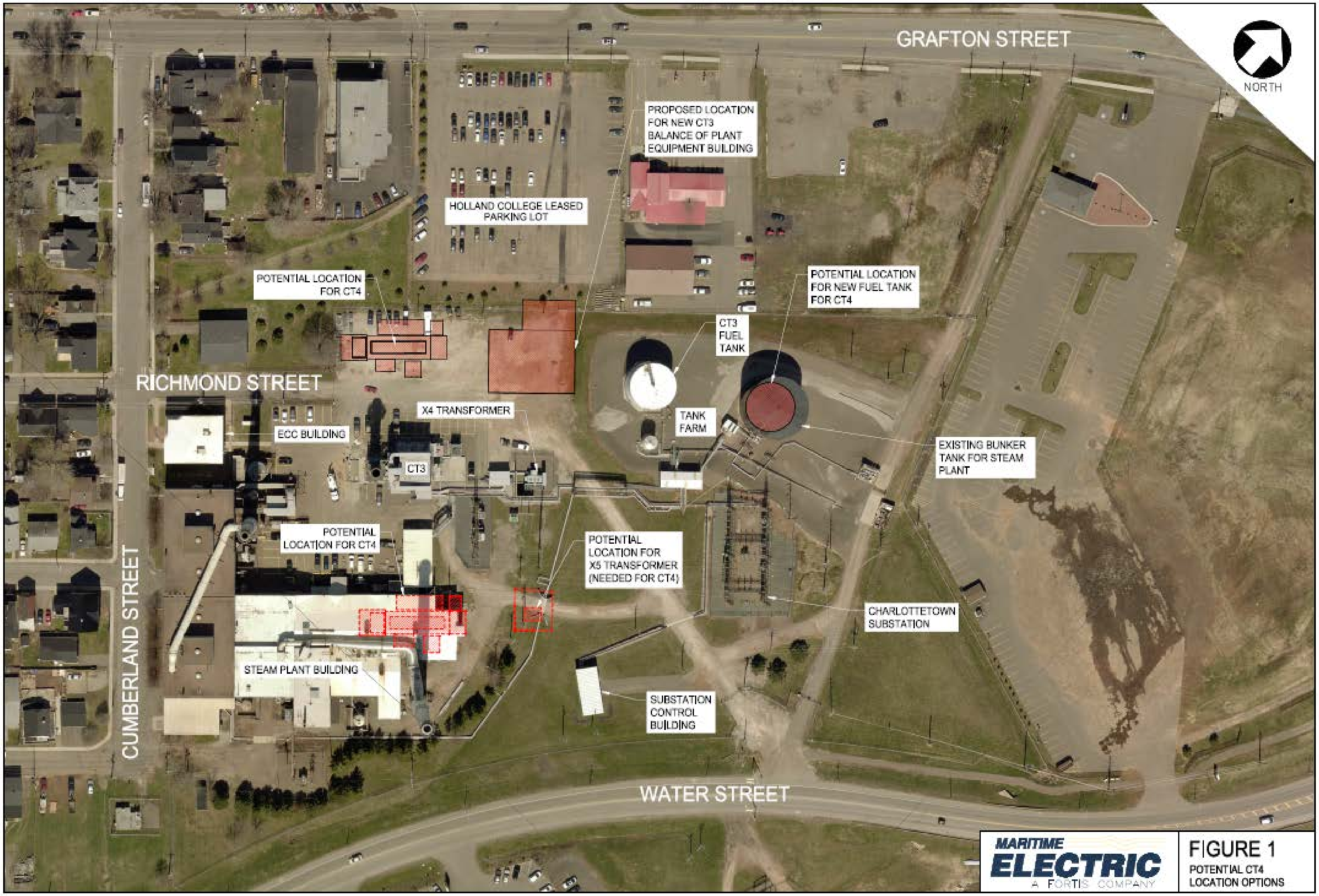
Order UE09-02 - Non-Recoverable Fortis Inc. Expenses	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009
Salaries	$ 304,000	$ 367,000	$ 400,000	$ 294,000	$ 251,000	$ 180,000	$ 209,000	$ 208,000	$ 127,000	$ 26,000
Directors' fees and costs	40,000	60,000	58,000	36,000	96,000	44,000	74,000	52,000	76,000	62,000
Trustees and DRIP administration	7,000	8,000	10,000	11,000	15,000	17,000	19,000	19,000	16,000	15,000
Consulting	28,000	24,000	24,000	-	-	-	-	-	-	-
Legal	24,000	9,000	19,000	-	-	-	-	-	-	-
Consulting & legal fees	-	-	-	43,000	55,000	36,000	56,000	48,000	39,000	41,000
Audit	21,000	12,000	13,000	10,000	13,000	13,000	12,000	17,000	14,000	12,000
Listing and filing	15,000	17,000	20,000	12,000	18,000	16,000	24,000	26,000	18,000	21,000
Annual meeting and report	13,000	16,000	23,000	11,000	12,000	13,000	18,000	15,000	14,000	14,000
Other fees/costs	3,000	4,000	4,000	45,000	32,000	34,000	37,000	40,000	35,000	36,000
Occupancy	17,000	16,000	19,000	-	-	-	-	-	-	-
Insurance	12,000	10,000	14,000	7,000	9,000	13,000	16,000	17,000	18,000	17,000
Office related	15,000	19,000	20,000	-	-	-	-	-	-	-
Investor Relations	8,000	20,000	18,000	-	-	-	-	-	-	-
Communications	4,000	-	5,000	-	-	-	-	-	-	-
Miscellaneous	4,000	9,000	-	-	-	-	-	-	-	-
Travel	16,000	21,000	14,000	16,000	22,000	16,000	9,000	21,000	19,000	20,000
Telephone	3,000	-	-	-	-	-	-	-	-	-
Subtotal	534,000	612,000	661,000	485,000	523,000	382,000	474,000	463,000	376,000	264,000
Tax	(165,540)	(189,720)	(204,910)	(150,350)	(165,268)	(118,420)	(146,940)	(150,475)	(123,977)	(92,430)
Fortis Inc. Non Recoverable Expenses	**$ 368,460**	**$ 422,280**	**$ 456,090**	**$ 334,650**	**$ 357,732**	**$ 263,580**	**$ 327,060**	**$ 312,525**	**$ 252,023**	**$ 171,570**

I N T E R R O G A T O R I E S

Section IR-66

ATTACHMENT

Potential CT4 Location Options on the Cumberland Street Site



INTERROGATORIES

Section IR-67

ATTACHMENT

May 14, 2019 Reference No. 11149943

Kent Nicholson, MBA, P. Eng.
50 Cumberland Street
Charlottetown, PE C1A 5B9

Dear Mr. Nicholson:

Re: Cost Estimate Classification
Closure of the Charlottetown Thermal Generating Station
Charlottetown, Prince Edward Island

In 2017/2018, GHD was retained by Maritime Electric Company Limited to prepare a Decommissioning Study for the closure of the Charlottetown Thermal Generating Station (CTGS) located in Charlottetown, Prince Edward Island. The 2018 Decommissioning Study included decommissioning and demolition plans and closure cost forecasting specific to the Steam Plant infrastructure located at the CTGS. This letter is written to describe the cost estimate classification that GHD used in developing the closure cost forecasting as part of the 2018 Decommissioning Study, and provides recommendations for future refinement of the cost estimate.

As part of the 2018 Decommissioning Study, GHD developed a Class B Cost Estimate for Decommissioning of the CTGS. The Class B estimate as defined by the Treasury Board (TB) of the Canadian Federal Government is suitable to be used for budget authorization and/or project authorization and is comparable to a Class 3 cost estimate as defined by the Association for the Advancement of Costing Engineering (AACE) International. The methodology used to develop this estimate is based mainly on measured, priced, and detailed quantities, where possible, and is considered to have an accuracy range of -20 to +30 percent (%) when completed at the 20 to 35% project completion stage. It is noted that project completion under the TB and AACE costing methodologies is referring to the project design and planning phase of the project. It is estimated that the design and planning phase of the project was at a 30 to 35% completion stage at the time of completion of the Class B cost estimate, based on the following work completed for the preparation of the 2018 Decommissioning Study:

- Detailed quantity take-offs and asset inventory;
- Preliminary pricing obtained from third party vendors for specific project components;
- Phase II Environmental Site Assessment and hazardous materials inventories;
- Preliminary project options analysis;
- Draft bid/tendering document development; and
- Initial regulatory and municipal consultation.

As additional work is completed and the project design and planning phase proceeds, it is recommended that the Class B estimate be refined to a Class A cost estimate (equivalent to an AACE Class 1) at the

95% to 100% completion stage (i.e., just prior to bid tendering). At the 95% to 100% completion stage, it is anticipated that the following work will have been completed, which may affect the closure cost forecasting in the 2018 Class B estimate.

- Approval from Island Regulatory and Appeals Commission (IRAC) to proceed with demolition of the Steam Plant Building and associated infrastructure.
- Preparation and submission of Environmental Impact Assessment (EIA) project registration document to the Prince Edward Island Department of Communities, Land and Environment (PEICLE). As part of the EIA Approval/Determination issued from PEICLE for the CTGS closure, it is anticipated that several conditions in the Approval will include monitoring and/or controls for protection of the public, workers, and the environment.
- Additional stakeholder consultation, including public and municipal consultation. Stakeholder consultation will be included as part of EIA registration process and results of the consultation process will determine the requirement for additional monitoring, controls, and/or modification of demolition methodologies for inclusion in the project scope of work.
- Completion of detailed designs and quantity takes offs (e.g., shoreline restoration, storm water infrastructure upgrades) and finalization of tender documents and technical specifications.

In addition to the work that will be done as the design and planning phase proceeds to completion, there are several external factors that should also be refined as part of updating the budget to a Class A cost estimate, including potential innovative stack demolition methodologies, changes in environmental and/or safety regulations and fluctuations in scrap value. These items have the potential to significantly affect the budget at the time of demolition commencement but are difficult to predict at this time.

Significant innovation for concrete stack demolition has been achieved in the past several years related to the decommissioning of numerous coal-fired power generation stations in the United States. Given the recent advancement in demolition techniques specific to stacks, it is reasonable to expect that new demolition methods may be available at the time of CTGS closure that may reduce costs and/or improve safety precautions specific to demolition of the CTGS stacks. As such, it is recommended that the costing included in the 2018 Class B estimate for demolition of the stacks (i.e., combination of mast-climbers and high reach excavators) be reviewed and the budget be updated as part of the technical specification development and bid tendering process.

Environmental and safety regulations are subject to change based on industry trends and can significantly impact a project budget. Therefore, it is recommended that following the EIA Determination/Approval process and as part of the bid tendering process, a thorough regulatory review of environmental and safety requirements be completed and the project specifications and budget be updated accordingly.

Scrap metal pricing fluctuates monthly, and sometimes even daily, adapting and changing with global market conditions, industry supply and demand, and time of year. As a demonstration of the variabilities of scrap pricing, GHD compared the spot metal prices obtained in February 2018 during completion of the

2018 Decommissioning Study with current scrap metal prices in May 2019. The variability is summarized in the table below:

Table 1 Scrap Metal Pricing - 2018 to 2019

Scrap Type	Spot Metal Pricing February 2018* (CAD $/tonne)	Spot Metal Pricing May 9, 2019* (CAD $/tonne)	Relative % Difference
Plate and Structural Standard Carbon Steel	205.00	240.00	+15.7%
Standard Carbon Steel/Cast iron/Wrought Iron (Pipes, Cladding, Ducting)	205.00	240.00	+15.7%
Stainless Steel (Tanks, Pipes, Tubing)	1430.00	1499.00	+4.7%
Bare Copper	7502.00	6834.00	-9%
Aluminum	1430.00	1102.00	-20%
Brass	5896.00	5467.50	-7.5%

*Spot Metal Pricing obtained from AIM Recycling Hamilton, Ontario website (http://ontariopricelist.scrapmetal.net/pricelist.php)

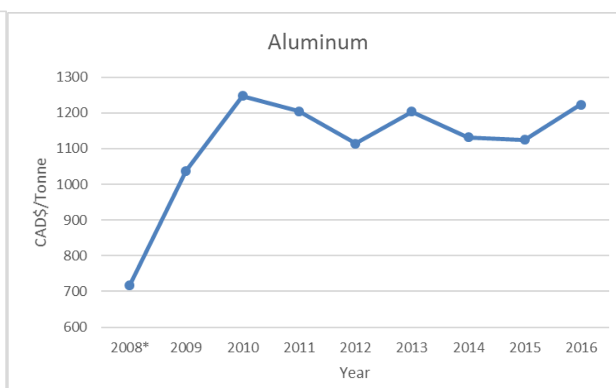
As can be seen from the results in the Table 1 above, scrap values have fluctuated over the last year and are anticipated to be volatile over the next several years which can have a significant impact on a demolition bid.

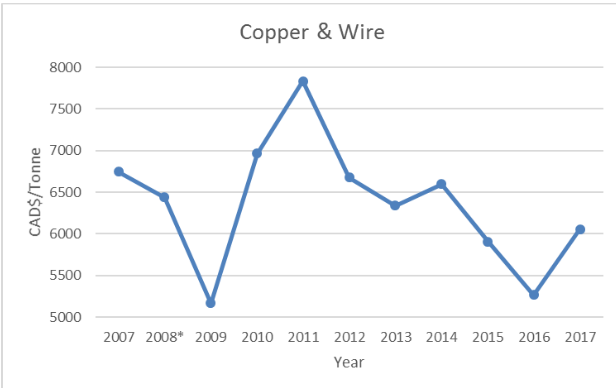
For comparison purposes, Table 2 and the corresponding graphs below summarizes the average scrap values over an 11-year period between 2007 and 2017 (for the more common types of scrap that would be found in a power plant such as the CTGS). As can be seen in the graphs below, values of the various scrap components had large swings over a very short time frame between 2007 and 2017 and this volatility is likely to continue into the future. In particular, the maximum scrap values for each component were approximately 50 to >100% greater than the minimum values over the 11-year period. As such, timing of the facility closure project and industry trends in scrap metal values could have a significant effect on the overall cost of the project and bid prices received from demolition contractors. The table and graphs below highlight the difficulty predicting future scrap values when planning for a decommissioning project and the importance of refining the project cost estimate prior to issuing the tender for bids. Given that the CTGS is not scheduled to be demolished until 2022 (four years after issuing the 2018 Decommissioning Study Class B estimate) it is highly recommended that current scrap values be considered and the Class B estimate be updated accordingly prior to issuing the tender for bids.

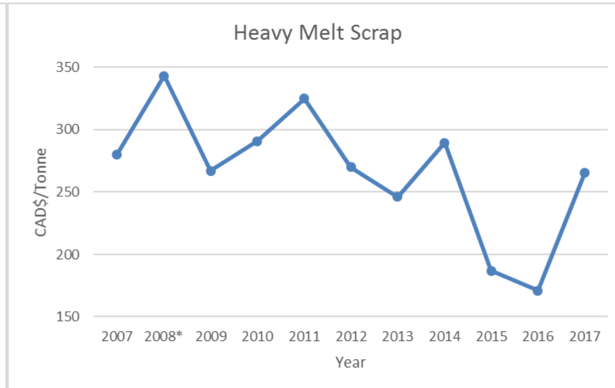
Table 2 Scrap Metal Pricing - 2007 to 2017

Material	Stainless Steel		Aluminum (Mixed low-copper clips)		No. 1 Heavy Copper & Wire		No. Heavy Melt Scrap	
Year	CAD ¢/lb	CAD $/tonne	CAD ¢/lb	CAD $/tonne	CAD ¢/lb	CAD $/tonne	CAD $/net ton	CAD $/tonne
	Average Price		Average Price		Average Price		Average Price	
2007	132.70	2918.30	NA	NA	306.70	6746.30	254.74	280.21
2008*	101.54	2233.92	NA	625.90	292.61	6437.38	312.10	343.31
2009	83.51	1815.21	33.62	717.86	234.94	5168.72	242.86	267.15
2010	119.11	2620.39	47.17	1,038	316.66	6966.48	264.43	290.87
2011	116.97	2573.41	56.69	1,247	356.02	7832.37	295.50	325.05
2012	87.96	2070.62	54.73	1,204	303.41	6675.02	245.54	270.10
2013	71.90	1581.80	50.65	1114.30	288.08	6337.76	223.35	246.20
2014	69.90	1537.80	54.72	1203.84	299.95	6598.90	263.12	289.44
2015	56.51	1243.22	51.41	1131.02	268.47	5906.34	169.54	186.88
2016	68.07	1497.54	51.10	1124.20	239.27	5263.94	155.14	171.01
2017	82.08	1805.76	55.60	1223.20	275.25	6055.50	240.96	265.61
11 Year Average	90.82	1990.72	50.01	1045.12	289.21	6362.61	242.48	266.89
May 2019 Spot Check		1499.00		1102.00		6834.00		240.00
Relative Percent Difference (%)	-28.2		5.3		7.1		-10.6	

Notes:
1 Prices based on materials delivered to Montreal market
2 Sources of scrap metal pricing based on information obtained from on-line resources such as American Metals Market, American Iron & Metals and scrap metal values obtained from other decommissioning/demolition projects completed in Eastern Canada
3 Relative Percent Difference is calculated based on difference in average price for specific metal between 2007 and 2017 versus current spot price
* Only November and December 2008 data available for Aluminum







In addition to the above factors, the timing selected for completion of this project (i.e., issuing the tender for bids) and other on-going or planned large demolition projects in Eastern Canada or United States can have a significant impact on pricing received from contractors to conduct the work. It is recommended that a review of other competing demolition projects be completed and communication with potential bidders regarding workloads be conducted prior to the release of the tender documents for bidding. This would help ensure that bids are received during perceived industry down-turns or non-construction seasons (winter) when contractor workloads are typically low and contractors are aggressively bidding work. Prior to issuing the tender documents, the Class B cost estimate should be reviewed with respect to any potential changes in the demolition contractor labour market and the cost estimate updated if required.

The Class B cost estimate presented in the 2018 Decommissioning Study was prepared in such a manner that easily allows for refinement of contractor labour costs and updating salvage values. Therefore, GHD recommends that the existing Class B cost estimate be refined to a Class A cost estimate upon achieving 95% to 100% completion of planning and design phase, once the regulatory approval to proceed with the project has been obtained and the tender documents are finalized, and prior to issuing the tender for bids.

Sincerely,

GHD

Troy Small, M.Sc., CE

CB/ad/7

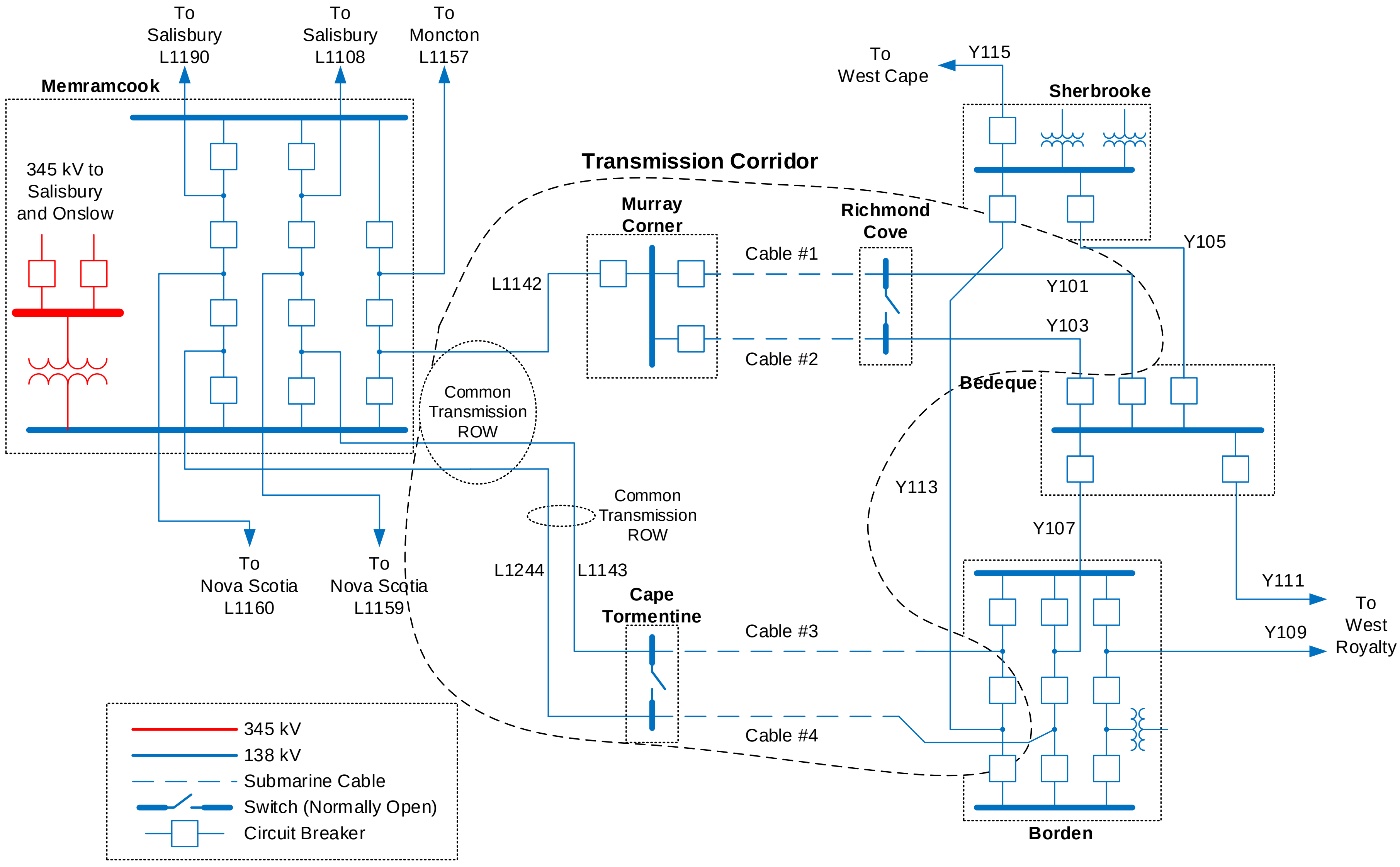
MARITIME ELECTRIC
A FORTIS COMPANY
All our energy.
All the time.

INTERROGATORIES

Section IR-73

ATTACHMENT

138 kV Lines (L1142, L1143 and L1244) and associated 138 kV Submarine Cables



MARITIME ELECTRIC
A FORTIS COMPANY
All our energy.
All the time.

I N T E R R O G A T O R I E S

Section IR-76

ATTACHMENT

Details of Actual and Forecast Energy Control Centre Labour Costs

			Actuals			Forecasts 2018 Hourly Rate, 2% CPI and 20% Overhead Rate			
		2016	2017	2018		2018	2019	2020	2021
		5 Operators	6 Operators	6.5 Operators	Budget	6.5 Operators	7 Operators	7 Operators	7 Operators
Hourly		$ 42.92	$ 44.00	$ 45.10	Hours	$ 45.10	$ 46.00	$ 46.92	$ 47.86
Regular	2184	$ 342,159	$ 465,980	$ 590,403	2184	$ 640,240	$ 703,279	$ 717,344	$ 731,691
OT	10	$ 2,078	$ 2,034	$ 6,252	10	$ 4,397	$ 4,830	$ 4,927	$ 5,025
DT	200	$ 42,615	$ 66,355	$ 51,649	200	$ 117,260	$ 128,806	$ 131,382	$ 134,009
					20%	$ 152,379	$ 167,383	$ 170,731	$ 174,145
						$ 914,276	$ 1,004,297	$ 1,024,383	$ 1,044,871
						75%	75%	75%	75%
		$ 386,852	$ 534,369	$ 648,304	Note 2	$ 685,707	$ 753,223	$ 768,287	$ 783,653
Supervision and Management	Note 1	128,980	123,397	170,292		185,200	200,197	225,115	219,715
Spare Operators from Other Departments		256,657	90,544	66,982	Note 3	72,693	115,480	114,098	119,532
		$ 772,489	$ 748,310	$ 885,578		$ 943,600	$ 1,068,900	$ 1,107,500	$ 1,122,900

Note 1 - 2016 & part of 2017, Manager was seconded to be project manager of cable project.

Note 2 - For budgeting purposes, 75% of ECC Operators time is allocated to ECC Operations and 25% to OATT Administration.

Note 3 - Timing of budget in spring of 2018 before full complement of ECC operators were hired so 2019 - 2021 budget still reflects an allocation for "spare" operators from other departments. As a result, budget for ECC operations should be lower and budget labour in T & D and generation should be higher.

MARITIME ELECTRIC
A FORTIS COMPANY
All our energy.
All the time.

I N T E R R O G A T O R I E S

Section IR-78

ATTACHMENT

Maritime Electric Company, Limited
Schedule of Rates

Rate Code		March 1, 2019	March 1, 2020	March 1, 2021
110	**Residential**			
	Service Charge	$ 24.57	$ 24.57	$ 24.57
	Energy Charge per kWh - First Block[1]	$ 0.1462	$ 0.1488	$ 0.1515
	Energy Charge per kWh for balance kWh	$ 0.1160	$ 0.1178	$ 0.1199
131	**Residential Seasonal**			
	Service Charge	$ 26.92	$ 26.92	$ 26.92
	Energy Charge per kWh - First Block[1]	$ 0.1462	$ 0.1488	$ 0.1515
	Energy Charge per kWh for balance of kWh	$ 0.1160	$ 0.1178	$ 0.1199
133	**Residential Seasonal Option**			
	Service Charge	$ 37.50	$ 37.50	$ 37.50
	Energy Charge per kWh - First Block[1]	$ 0.1462	$ 0.1488	$ 0.1515
	Energy Charge per kWh for balance of kWh	$ 0.1160	$ 0.1178	$ 0.1199
232	**General Service**			
	Service Charge	$ 24.57	$ 24.57	$ 24.57
	Demand Charge - per kW for first 20 kW	$ -	$ -	$ -
	Demand Charge - per kW for balance of kW	$13.43	$ 13.43	$ 13.43
	Energy Charge per kWh for first 5,000 kWh	$ 0.1800	$ 0.1834	$ 0.1869
	Energy Charge per kWh for balance of kWh	$ 0.1172	$ 0.1190	$ 0.1212
233	**General Service - Seasonal Operators Option**			
	Service Charge	$ 24.57	$ 24.57	$ 24.57
	Demand Charge - per kW for first 20 kW	$ -	$ -	$ -
	Demand Charge - per kW for balance of kW	$ 13.43	$ 13.43	$ 13.43
	Energy Charge per kWh for first 5,000 kWh	$ 0.1800	$ 0.1834	$ 0.1869
	Energy Charge per kWh for balance of kWh	$ 0.1172	$ 0.1190	$ 0.1212
320	**Small Industrial**			
	Demand Charge - per kW	$ 7.46	$ 7.46	$ 7.46
	Energy Charge per kWh for first 100 kWh per kW billing demand	$ 0.1764	$ 0.1797	$ 0.1831
	Energy Charge per kWh for balance of kWh	$ 0.0883	$ 0.0893	$ 0.0909
310	**Large Industrial**			
	Demand Charge per kW	$ 14.50	$ 14.50	$ 14.50
	Energy Charge per kWh	$ 0.0725	$ 0.0738	$ 0.0751
340	**Long Term Contract** (Currently no customers in this rate category)			
	Demand Charge per kW	$ 15.51	$ 15.51	$ 15.51
	Energy Charge per kWh	$ 0.0942	$ 0.0954	$ 0.0971
330	**Short Term Contract** (Currently no customers in this rate category)			
	Demand Charge - per kW	$ 16.79	$ 16.79	$ 16.79
	Energy Charge per kWh for all kWh in the first block	$ 0.0972	$ 0.0985	$ 0.1002
	Energy Charge per kWh for balance of kWh in the month	$ 0.0805	$ 0.0814	$ 0.0828

Maritime Electric Company, Limited
Schedule of Rates

	Residential	Type		Annual kWh	Monthly kWh	March 1, 2019	March 1, 2020	March 1, 2021
	619	LED	70 W HPS Equivalent St Lights - Rented		15	$ 12.24	$ 12.41	$ 12.58
	625	LED	100 W HPS Equivalent St Lights - Rented		17	$ 12.66	$ 12.84	$ 13.02
*	630	HPS	St Lights - Rented	389	32	$ 16.18	$ 16.41	$ 16.64
*	631	HPS	St Lights - Rented	553	46	$ 20.55	$ 20.84	$ 21.13
*	632	HPS	St Lights - Rented	799	66	$ 29.39	$ 29.80	$ 30.22
	633	HPS	St Lights - Rented	1283	106	$ 39.96	$ 40.52	$ 41.09
	634	HPS	St Lights - Rented	1886	157	$ 46.74	$ 47.39	$ 48.05
*	635	MV	St Lights - Rented	656	54	$ 16.03	$ 16.25	$ 16.48
	639	Lanterns	City Lanterns - Rented	389	32	$ 59.49	$ 60.32	$ 61.16
*	640	HPS	St Lights - Owned	389	32	$ 6.36	$ 6.45	$ 6.54
*	641	HPS	St Lights - Owned	553	46	$ 8.39	$ 8.51	$ 8.63
*	642	HPS	St Lights - Owned	779	65	$ 11.27	$ 11.43	$ 11.59
	643	HPS	St Lights - Owned	1283	107	$ 17.85	$ 18.10	$ 18.35
	644	HPS	St Lights - Owned	1886	157	$ 28.15	$ 28.54	$ 28.94
	666	LED	175 W MV Equivalent St Lights - Rented		25	$ 14.08	$ 14.28	$ 14.48
	670	LED	St Lights - Rented	410	34	$ 16.39	$ 16.62	$ 16.85
	675	LED	150 W/200 W HPS Equivalent St Lights - Rented		37	$ 15.22	$ 15.43	$ 15.65
	719	LED	St Lights - Owned	176	15	$ 2.59	$ 2.63	$ 2.67
*	730	HPS	Yard Lights - Rented	389	32	$ 16.18	$ 16.41	$ 16.64
*	731	HPS	Yard Lights - Rented	553	46	$ 20.55	$ 20.84	$ 21.13
*	732	HPS	Yard Lights - Rented	799	66	$ 29.39	$ 29.80	$ 30.22
	733	HPS	Yard Lights - Rented	1283	106	$ 39.96	$ 40.52	$ 41.09
	734	HPS	Yard Lights - Rented	1886	157	$ 46.74	$ 47.39	$ 48.05
*	735	MV	Yard Lights - Rented	656	54	$ 16.03	$ 16.25	$ 16.48
*	736	MV	Yard Lights - Rented	881	73	$ 20.37	$ 20.66	$ 20.95
*	737	MV	Yard Lights - Rented	1210	100	$ 28.34	$ 28.74	$ 29.14
*	740	HPS	Yard Lights - Owned	389	32	$ 6.36	$ 6.45	$ 6.54
*	741	HPS	Yard Lights - Owned	553	46	$ 8.39	$ 8.51	$ 8.63
	742	HPS	Yard Lights - Owned	779	65	$ 11.27	$ 11.43	$ 11.59
	743	HPS	Yard Lights - Owned	1283	107	$ 17.85	$ 18.10	$ 18.35
	744	HPS	Yard Lights - Owned	1886	157	$ 28.15	$ 28.54	$ 28.94
	749	LPS	Yard Lights - Owned	869	72	$ 13.13	$ 13.31	$ 13.50
	753	Flood	Yard Lights - Rented	1283	107	$ 38.13	$ 38.66	$ 39.20
	754	Flood	Yard Lights - Rented	1886	157	$ 47.47	$ 48.13	$ 48.80
	755	Halide	Yard Lights - Rented	1148	95	$ 40.15	$ 40.71	$ 41.28
	756	Halide	Yard Lights - Rented	1878	156	$ 49.42	$ 50.11	$ 50.81
	757	Halide	Yard Lights - Rented	4346	362	$ 84.82	$ 86.01	$ 87.21
	759	Halide	St Lights - Owned	533	44	$ 7.84	$ 7.95	$ 8.06
	760	Halide	St Lights - Owned	894	74	$ 13.16	$ 13.34	$ 13.53
	761	Halide	St Lights - Owned	1148	95	$ 16.88	$ 17.12	$ 17.36
	762	Halide	St Lights - Owned	1878	156	$ 27.60	$ 27.99	$ 28.38
	764	LED	St Lights - Owned	410	34	$ 6.02	$ 6.10	$ 6.19
	765	Halide	St Lights - Owned	759	63	$ 11.15	$ 11.31	$ 11.47
	766	LED	St Lights - Owned	295	25	$ 4.33	$ 4.39	$ 4.45
	775	LED	St Lights - Owned	438	37	$ 6.44	$ 6.53	$ 6.62
	780	LED	St Lights - Owned	586	49	$ 8.62	$ 8.74	$ 8.86
	785	LED	St Lights - Owned	718	60	$ 10.54	$ 10.69	$ 10.84

* These charges are applicable to existing fixtures only.

Maritime Electric Company, Limited

Schedule of Rates

		March 1, 2019	March 1, 2020	March 1, 2021
610	Pole Rental -Wood	$ 4.38	$ 4.38	$ 4.38
	Residential			
	Unmetered Rates (based on 100 watt fixture)			
810	8 Hour Lighting per kWh	$ 0.1762	$ 0.1787	$ 0.1812
	Minimum Charge	$ 0.11	$ 0.11	$ 0.11
820	12 Hour Lighting per kWh	$ 0.1762	$ 0.1787	$ 0.1812
	Minimum Charge	$ 11.67	$ 11.67	$ 11.67
830	24 Hour Lighting per kWh	$ 0.1762	$ 0.1787	$ 0.1812
	Minimum Charge	$ 11.67	$ 11.67	$ 11.67
840	Air Raid & Fire Sirens	Currently no customers in this rate category		
850	Outdoor Christmas Lighting - 5.77¢ per watt of connected load per week			
234	Customer Owned Outdoor Recreational Lighting			
	Service Charge	$ 24.57	$ 24.57	$ 24.57
	Energy Charge per kWh for first 5,000 kWh	$ 0.1762	$ 0.1787	$ 0.1812
	Energy Charge per kWh for balance of kWh	$ 0.1082	$ 0.1097	$ 0.1112
	Short Term Unmetered Rates	Currently no customers in this rate category		
	Energy Charge:			
	per kWh of estimated consumption	$ 0.1762	$ 0.1787	$ 0.1812

Connection Charge:

	Three-Phase
A. Connecting to existing secondary voltage	$99.08

B. Where transformer installations are required, the following connection charges will apply:

	Single-Phase	Three-Phase
(1) Up to and including 10 kVA	$148.87	$209.17
(2) 11 kVA to 15 kVA	$240.79	$301.01
(3) 16 kVA to 25 kVA	$269.20	$336.64
(4) 26 kVA to 37 kVA	$301.01	$336.64
(5) 38 kVA to 50 kVA	$336.64	$336.64
(6) 51 kVA to 75 kVA	$369.58	$523.96
(7) 76 kVA to 125 kVA	$431.07	$555.59
(8) Above 125 kVA	0	$594.94

I N T E R R O G A T O R I E S

Section IR-81

ATTACHMENT

Composition of Total Energy Charger per kWh for Each Rate Class				
July 1, 2019 Implementation				
Energy Charge per kWh - Revenue Requirement (A)				
	March 1, 2018	**July 1, 2019**	**March 1, 2020**	**March 1, 2021**
Residential - First Block	$ 0.140900	$ 0.143600	$ 0.146900	$ 0.149900
Residential - Second Block	$ 0.111400	$ 0.113600	$ 0.116200	$ 0.118600
General Service - First Block	$ 0.173900	$ 0.177300	$ 0.181300	$ 0.184900
General Service - Second Block	$ 0.112600	$ 0.114800	$ 0.117400	$ 0.119700
Small Industrial - First Block	$ 0.170300	$ 0.173600	$ 0.177500	$ 0.181100
Small Industrial - Second Block	$ 0.084400	$ 0.086000	$ 0.087900	$ 0.089700
Large Industrial	$ 0.068600	$ 0.069500	$ 0.072200	$ 0.074000

Energy Charges per kWh - Other Amounts (B)				
	March 1, 2018	**July 1, 2019**	**March 1, 2020**	**March 1, 2021**
ECAM Charge per kWh	$ 0.000575	$ 0.005127	$ 0.002833	$ 0.002026
Provincial Costs Recoverable per kWh	$ 0.005360	$ -	$ -	$ -
Provincial Energy Efficiency Program per kWh	$ -	$ 0.000700	$ 0.000800	$ 0.000900
Cable Contingency Fund per kWh	$ 0.000270	$ -	$ -	$ -
RORA per kWh	$ (0.003445)	$ (0.002392)	$ (0.002392)	$ (0.002392)
Subtotal per kWh	$ 0.002800	$ 0.003400	$ 0.001200	$ 0.000500

Total Energy Charge per kWh (A + B)				
	March 1, 2018	**July 1, 2019**	**March 1, 2020**	**March 1, 2021**
Residential - First Block	$ 0.143700	$ 0.147000	$ 0.148100	$ 0.150400
Residential - Second Block	$ 0.114200	$ 0.117000	$ 0.117400	$ 0.119100
General Service - First Block	$ 0.176700	$ 0.180700	$ 0.182500	$ 0.185400
General Service - Second Block	$ 0.115400	$ 0.118200	$ 0.118600	$ 0.120200
Small Industrial - First Block	$ 0.173100	$ 0.177000	$ 0.178700	$ 0.181600
Small Industrial - Second Block	$ 0.087200	$ 0.089400	$ 0.089100	$ 0.090200
Large Industrial	$ 0.071400	$ 0.072900	$ 0.073400	$ 0.074500

Composition of Total Energy Charger per kWh for Each Rate Class				
August 1, 2019 Implementation				
Energy Charge per kWh - Revenue Requirement (A)				
	March 1, 2018	**August 1, 2019**	**March 1, 2020**	**March 1, 2021**
Residential - First Block	$ 0.140900	$ 0.143500	$ 0.146600	$ 0.149700
Residential - Second Block	$ 0.111400	$ 0.113500	$ 0.115900	$ 0.118300
General Service - First Block	$ 0.173900	$ 0.177200	$ 0.181100	$ 0.185000
General Service - Second Block	$ 0.112600	$ 0.114700	$ 0.117200	$ 0.119700
Small Industrial - First Block	$ 0.170300	$ 0.173500	$ 0.177300	$ 0.181100
Small Industrial - Second Block	$ 0.084400	$ 0.086000	$ 0.087900	$ 0.089800
Large Industrial	$ 0.068600	$ 0.069200	$ 0.072000	$ 0.074000

Energy Charges per kWh - Other Amounts (B)				
	March 1, 2018	**August 1, 2019**	**March 1, 2020**	**March 1, 2021**
ECAM Charge per kWh	$ 0.000575	$ 0.005704	$ 0.003102	$ 0.002117
Provincial Costs Recoverable per kWh	$ 0.005360	$ -	$ -	$ -
Provincial Energy Efficiency Program per kWh	$ -	$ 0.000700	$ 0.000800	$ 0.000900
Cable Contingency Fund per kWh	$ 0.000270	$ -	$ -	$ -
RORA per kWh	$ (0.003445)	$ (0.002362)	$ (0.002362)	$ (0.002362)
Subtotal per kWh	$ 0.002800	$ 0.004000	$ 0.001500	$ 0.000700

Total Energy Charge per kWh (A + B)				
	March 1, 2018	**August 1, 2019**	**March 1, 2020**	**March 1, 2021**
Residential - First Block	$ 0.143700	$ 0.147500	$ 0.148100	$ 0.150400
Residential - Second Block	$ 0.114200	$ 0.117500	$ 0.117400	$ 0.119000
General Service - First Block	$ 0.176700	$ 0.181200	$ 0.182600	$ 0.185700
General Service - Second Block	$ 0.115400	$ 0.118700	$ 0.118700	$ 0.120400
Small Industrial - First Block	$ 0.173100	$ 0.177500	$ 0.178800	$ 0.181800
Small Industrial - Second Block	$ 0.087200	$ 0.090000	$ 0.089400	$ 0.090500
Large Industrial	$ 0.071400	$ 0.073200	$ 0.073500	$ 0.074700

Composition of Total Energy Charger per kWh for Each Rate Class				
September 1, 2019 Implementation				
Energy Charge per kWh - Revenue Requirement (A)				
	March 1, 2018	**September 1, 2019**	**March 1, 2020**	**March 1, 2021**
Residential - First Block	$ 0.140900	$ 0.143400	$ 0.146400	$ 0.149800
Residential - Second Block	$ 0.111400	$ 0.113400	$ 0.115800	$ 0.118500
General Service - First Block	$ 0.173900	$ 0.177100	$ 0.180700	$ 0.184900
General Service - Second Block	$ 0.112600	$ 0.114700	$ 0.117100	$ 0.119900
Small Industrial - First Block	$ 0.170300	$ 0.173500	$ 0.177100	$ 0.181300
Small Industrial - Second Block	$ 0.084400	$ 0.086000	$ 0.087800	$ 0.089900
Large Industrial	$ 0.068600	$ 0.068700	$ 0.071700	$ 0.073900

Energy Charges per kWh - Other Amounts (B)				
	March 1, 2018	**September 1, 2019**	**March 1, 2020**	**March 1, 2021**
ECAM Charge per kWh	$ 0.000575	$ 0.006494	$ 0.003414	$ 0.002316
Provincial Costs Recoverable per kWh	$ 0.005360	$ -	$ -	$ -
Provincial Energy Efficiency Program per kWh	$ -	$ 0.000700	$ 0.000800	$ 0.000900
Cable Contingency Fund per kWh	$ 0.000270	$ -	$ -	$ -
RORA per kWh	$ (0.003445)	$ (0.002328)	$ (0.002328)	$ (0.002328)
Total Energy Charge per kWh Excluding Basic Revenue	$ 0.002800	$ 0.004900	$ 0.001900	$ 0.000900

Total Energy Charge per kWh (A + B)				
	March 1, 2018	**September 1, 2019**	**March 1, 2020**	**March 1, 2021**
Residential - First Block	$ 0.143700	$ 0.148300	$ 0.148300	$ 0.150700
Residential - Second Block	$ 0.114200	$ 0.118300	$ 0.117700	$ 0.119400
General Service - First Block	$ 0.176700	$ 0.182000	$ 0.182600	$ 0.185800
General Service - Second Block	$ 0.115400	$ 0.119600	$ 0.119000	$ 0.120800
Small Industrial - First Block	$ 0.173100	$ 0.178400	$ 0.179000	$ 0.182200
Small Industrial - Second Block	$ 0.087200	$ 0.090900	$ 0.089700	$ 0.090800
Large Industrial	$ 0.071400	$ 0.073600	$ 0.073600	$ 0.074800

Composition of Total Energy Charger per kWh for Each Rate Class

October 1, 2019 Implementation

Energy Charge per kWh - Revenue Requirement (A)	March 1, 2018	October 1, 2019	March 1, 2020	March 1, 2021
Residential - First Block	$ 0.140900	$ 0.143400	$ 0.146100	$ 0.149800
Residential - Second Block	$ 0.111400	$ 0.113400	$ 0.115600	$ 0.118500
General Service - First Block	$ 0.173900	$ 0.177400	$ 0.180600	$ 0.185100
General Service - Second Block	$ 0.112600	$ 0.114900	$ 0.117000	$ 0.119900
Small Industrial - First Block	$ 0.170300	$ 0.173700	$ 0.176800	$ 0.181200
Small Industrial - Second Block	$ 0.084400	$ 0.086100	$ 0.087600	$ 0.089800
Large Industrial	$ 0.068600	$ 0.068100	$ 0.071400	$ 0.073800

Energy Charges per kWh - Other Amounts (B)	March 1, 2018	October 1, 2019	March 1, 2020	March 1, 2021
ECAM Charge per kWh	$ 0.000575	$ 0.007561	$ 0.003733	$ 0.002368
Provincial Costs Recoverable per kWh	$ 0.005360	$ -	$ -	$ -
Provincial Energy Efficiency Program per kWh	$ -	$ 0.000700	$ 0.000800	$ 0.000900
Cable Contingency Fund per kWh	$ 0.000270	$ -	$ -	$ -
RORA per kWh	$ (0.003445)	$ (0.002293)	$ (0.002293)	$ (0.002293)
Total Energy Charge per kWh Excluding Basic Revenue	$ 0.002800	$ 0.006000	$ 0.002200	$ 0.001000

Total Energy Charge per kWh (A + B)	March 1, 2018	October 1, 2019	March 1, 2020	March 1, 2021
Residential - First Block	$ 0.143700	$ 0.149400	$ 0.148300	$ 0.150800
Residential - Second Block	$ 0.114200	$ 0.119400	$ 0.117800	$ 0.119500
General Service - First Block	$ 0.176700	$ 0.183400	$ 0.182800	$ 0.186100
General Service - Second Block	$ 0.115400	$ 0.120900	$ 0.119200	$ 0.120900
Small Industrial - First Block	$ 0.173100	$ 0.179700	$ 0.179000	$ 0.182200
Small Industrial - Second Block	$ 0.087200	$ 0.092100	$ 0.089800	$ 0.090800
Large Industrial	$ 0.071400	$ 0.074100	$ 0.073600	$ 0.074800